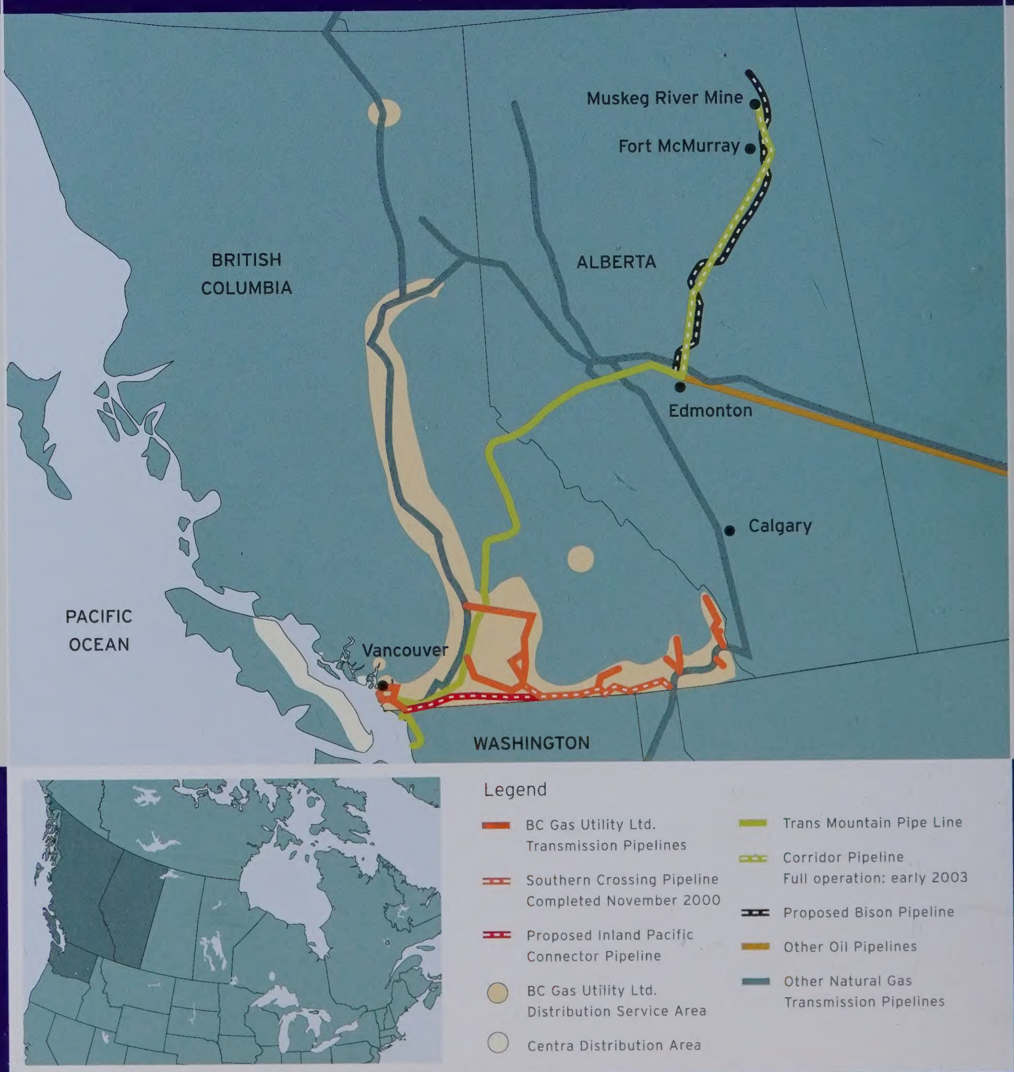
BC GAS INC. 2001 ANNUAL REPORT

BC GAS INC. AREA OF OPERATIONS



BC GAS INC. BUSINESS PROFILE

BC Gas Inc. is a leading energy distribution and transportation company as well as a provider of services related to energy and water distribution. Operating primarily in British Columbia and Alberta, the Company intends to strengthen and expand its base businesses to become the leading multi-utility gas, electric, water and oil asset manager in the Pacific Northwest.

Common shares of BC Gas Inc. are traded on The Toronto Stock Exchange under the symbol BCG. The Company's head office is in Vancouver, British Columbia.

NATURAL GAS DISTRIBUTION

BC Gas Utility is the largest distributor of natural gas in British Columbia, serving 767,000 customers in more than 100 communities. The acquisition of Centra Gas British Columbia – scheduled to be completed in March 2002 – will add an additional 70,000 customers and expand our gas distribution asset base. The Company is currently developing the Inland Pacific Connector Project to connect the Southern Crossing Pipeline to the Huntingdon-Sumas regional market hub.

PETROLEUM TRANSPORTATION

Trans Mountain Pipe Line owns and operates the only pipeline transporting crude oil and refined petroleum products from Alberta to British Columbia and Washington State. With the Corridor Pipeline – scheduled for full operation in early 2003 – and the proposed Bison Pipeline, the Company will be a leading provider of pipeline transportation services for the developing Athabasca oil sands deposit in northeastern Alberta.

MULTI-UTILITY SERVICES

BC Gas Inc. continues to develop its energy and water services business, primarily through the following companies:

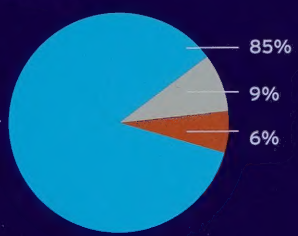
- BCG Services: Water distribution utility services
- CustomerWorks: Comprehensive customer care services for utilities, municipalities and energy services companies (BC Gas owns 30 per cent of CustomerWorks)
- ENRG: Largest natural gas fueling company in North America (BC Gas owns 56 per cent of ENRG)
- BC Gas International: Engineering and consulting services, primarily in the Persian Gulf

In 2001, BC Gas' natural gas and petroleum transportation businesses represented 94 per cent of revenues and 97 per cent of assets.

Year ended December 31, 2001

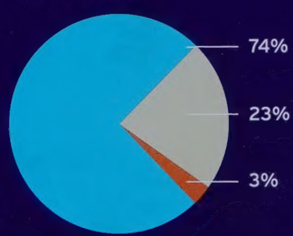
- Natural Gas Distribution
- Petroleum Transportation
- Other Activities

REVENUE



Total: $1,666.3 million

TOTAL ASSETS



Total: $3,705.7 million

FINANCIAL HIGHLIGHTS

BC Gas' share price, which has outperformed our peer group over the past five years, reflects our consistent financial performance. We are committed to achieving our financial targets while maintaining a low risk profile and focusing on our core businesses.

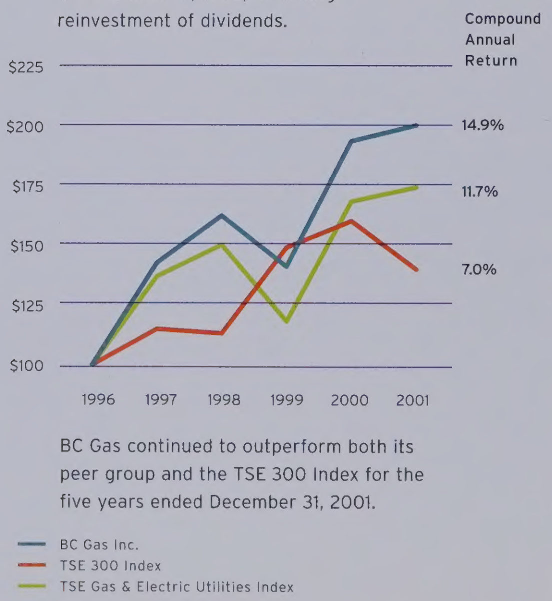
FINANCIAL RESULTS

(dollar amounts in millions except per share data)

Years ended December 31	**2001**	2000	1999
Gross revenues	**$ 1,666.3**	$ 1,305.6	$ 1,040.6
Earnings before non-recurring items	**$ 84.6**	$ 78.8	$ 74.2
Earnings applicable to common shares	**$ 84.6**	$ 108.8	$ 81.2
Total assets	**$ 3,705.7**	$ 3,513.1	$ 2,480.9
Earnings per share before non-recurring items	**$ 2.21**	$ 2.06	$ 1.94
Earnings per share	**$ 2.21**	$ 2.84	$ 2.12
Dividends per share	**$ 1.300**	$ 1.225	$ 1.165
Book value per share	**$ 18.65**	$ 17.86	$ 16.36
Return on common equity	**12.1%**	12.0%	12.2%

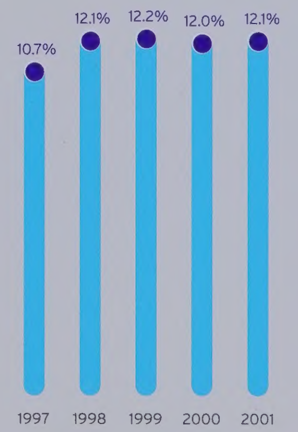
SHAREHOLDER RETURN

Return on an investment of $100 at December 31, 1996, assuming reinvestment of dividends.



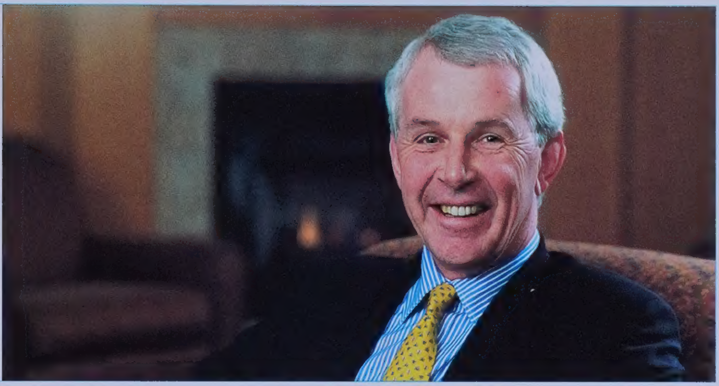
BC Gas continued to outperform both its peer group and the TSE 300 Index for the five years ended December 31, 2001.

RETURN ON COMMON EQUITY



In 2001, BC Gas again achieved its targeted return on equity of 12 per cent.

JOHN M. REID
President and
Chief Executive Officer



LETTER TO SHAREHOLDERS

We achieved a number of successes over the past year as we implemented our strategic plan, focused on strengthening and expanding our natural gas distribution and petroleum transportation businesses. We are also growing in a measured way from our core competencies into water and electricity transportation and services. Our approach provides a low risk profile that generates attractive growth for shareholders.

2001 may be remembered as the year when the debates and the controversies about energy provided more heat and light than the commodities themselves.

The California crisis forced Pacific Gas and Electric, the largest gas and electric utility in the U.S., into bankruptcy. The President of the U.S. introduced a comprehensive energy plan calling for North American self-reliance, which many understood to mean a harmonization or integration of the energy supplies in the NAFTA nations. Alberta travelled a rocky road toward electric deregulation and Ontario hesitated. The major natural gas pipeline plans from Alaska and the Canadian North were resurrected; and major Canadian energy companies were absorbed by larger foreign-owned corporations. The year came to a conclusion with the collapse of Enron, once the proud herald of a new way of conducting business in energy and commodities trading, in the largest bankruptcy in history.

In British Columbia, the first half of 2001 was characterized by enormous public concern about energy prices. The Western region of North America, in which our natural gas distribution utility is located, went through a period when pricing was disconnected from the rest of the North American market. Insufficient pipe available to supply a soaring demand for natural gas created serious price distortions west

of the Rockies. Fortunately, a temperate winter followed by a mild summer in California allowed the natural gas market to return to a semblance of normalcy in the second half.

The second half of 2001 also saw a new political environment in British Columbia. The new government launched a regime of lower taxes, promised less regulation and named a task force to develop a new energy policy for British Columbia. This was a most welcome development as the energy sector, both upstream and downstream, had been characterized by public policy neglect in the preceding decade. We are hopeful, and are working with government, to ensure that a new public policy framework will result in a true energy advantage for British Columbia — one that facilitates the growth of the producing/generating sectors while promoting choice, security of supply and competitive pricing for consumers.

Throughout a tumultuous year BC Gas has maintained its equilibrium and continued on the path of steady earnings and growth we have travelled for a number of years. Over the past five years the size of the Company has doubled. We have worked to a tightly focused strategic plan based on strengthening and expanding our base businesses. We have continued to maintain a low business risk profile and delivered results on target. Our earnings per share before non-recurring items for 2001 were $2.21 compared with $2.06 for 2000. Our compound annual shareholder return for the past five years was 14.9 per cent compared with 7.0 for the TSE 300 and 11.7 for our peer group.

EXPANDING OUR BASE BUSINESS

A number of expansions to our base business were under construction or announced in the past year. The Corridor Pipeline, a $688 million project designed to move bitumen from the oil sands to Shell's

SOLID LOW RISK INVESTMENT IN A GROWING SECTOR

- Earnings Per Share Before Non-Recurring Items
  Earnings per share growth was seven per cent in 2001.
- Dividends Per Share
  Dividends to shareholders in 2001 were $1.30 per share, up 33 per cent from 1997.

upgrader plant near Edmonton, is under construction and on budget and on time to start up in April. In January of this year we were pleased to announce that we were engaged in studies with Petro-Canada and TrueNorth Energy to construct another pipeline, known as the Bison Pipeline, connecting the oil sands to the Edmonton area. This project represents an initial investment of approximately $800 million, increasing to about $1 billion when it reaches its maximum potential.

The purchase of Centra Gas British Columbia adds to the natural gas franchise area of BC Gas Utility. It is a natural fit and it represents good potential for growth of our natural gas customer base. We continue to pursue the development of the Inland Pacific Connector, which would extend our Southern Crossing Pipeline south and west to the Lower Mainland region of British Columbia.

STRENGTHENING OUR BASE BUSINESS

A new incentive toll mechanism was implemented for the mainline of Trans Mountain in 2001. Such a tolling device provides incentives to maximize efficiencies of the operation while continuing to operate in a customer oriented way. We have enjoyed excellent results under the first year of the incentive arrangement and delivery volumes increased from the previous year. Moving Trans Mountain's headquarters to Calgary is also yielding benefits as the Company and many of its key people are now active participants in the vibrant oil and gas industry headquartered in the city. It also allows us closer contact with the shippers, thereby strengthening relationships and allowing us to better understand their business needs.

The opening of a new control centre in Edmonton puts Trans Mountain at the heart of the petroleum refining and transportation network in Western Canada and has enabled the Company to gain new efficiencies

EARNINGS (LOSS) APPLICABLE TO COMMON SHARES

(dollar amounts in millions except per share data)

Years ended December 31	2001	2001 Per Share	2000	2000 Per Share
Natural gas distribution	**$ 67.8**	**$ 1.77**	$ 58.7	$ 1.53
Petroleum transportation	**27.3**	**0.71**	21.3	0.56
Other activities	**(10.5)**	**(0.27)**	(1.2)	(0.03)
Earnings before non-recurring items	**84.6**	**2.21**	78.8	2.06
Non-recurring items	**-**	**-**	30.0	0.78
Earnings applicable to common shares	**$ 84.6**	**$ 2.21**	$ 108.8	$ 2.84

through the consolidation of pipeline operations at its Edmonton terminal.

We are currently working toward a new performance based regulatory settlement for BC Gas Utility and for Centra to take effect January 1, 2003. The interim report of the Task Force on Energy Policy has called for regulation in B.C. to be more outcomes based than in the past and we look forward to such a development.

Effective January 1, 2002 a distinct management structure was created for the gas utility and Randy Jespersen was appointed President of BC Gas Utility. This move is intended to allow utility management to focus on the core business of natural gas distribution while the management of BC Gas Inc. focuses on business development and public policy issues that face the various companies in the group.

GROWING FROM OUR CORE COMPETENCIES

This is an area of our strategy where we are taking a very measured approach. It represents a small portion of our asset base but it also represents the seeds that may grow in future to be major parts of our corporate group.

CustomerWorks: This entity went into operation on January 1 of this year. It provides customer call response, measurement and billing services to utilities and municipalities in Canada. We have partnered with Enbridge to create this company of which we own 30 per cent. It is the largest entity of

Our Chairman Retires

RONALD L. CLIFF
Chairman

After 32 years of contribution to the growth and success of our Company, Ronald L. Cliff will be retiring as Chairman, BC Gas.

Ron has led us through a remarkable period in our history: from the Inland Natural Gas days of the 1970's when we were a small gas company pursuing rapid growth and franchise agreements with municipalities in the Interior, to our transformation into the third largest gas utility in Canada with the purchase of Trans Mountain Pipe Line Company in 1983 and BC Hydro Mainland Gas Division in 1988.

Ron's many achievements in business are matched by his dedication to the community. He is well known for his personal interest in philanthropy and community investment and was named a Member of the Order of Canada in 1985.

Ron's outstanding contributions and vision were instrumental in the development of the Company and we wish him the very best in the years ahead.

its kind in Canada and was immediately profitable on start-up with considerable prospects for growth.

BCG Services: As more communities focus on the need for quality water services and the need to promote water conservation through measures such as water metering, private sector involvement in the provision of water services is expected to grow. We regard BCG Services as our entry into this field with the potential to grow our multi-utility platform.

BC Gas International (BCGI): Our international group is presently providing engineering and consulting services in the Persian Gulf region. They have completed two phases of a new natural gas distribution system in Sharjah and are beginning the third phase. BCGI together with two partners was recently awarded a $42 million project to operate and maintain Oman's natural gas transmission system.

ENRG: We merged our eFuels business last year with Pickens Fuel Corp. to create the largest natural gas fueling company in North America. We own 56 per cent of the new company, ENRG, which is now based in California, a location where clean air advocates have created a progressive public policy environment for alternative fuel vehicles.

LOW RISK INVESTMENT

We continue to believe that our shareholders expect a low risk profile from us with a pattern of steady earnings growth and a reasonable yield on their investment. We regard the sale of subscription receipts in November to finance the Centra purchase – at $36.15 per receipt for a total of approximately $188.3 million – as a vote of confidence from the investment community in our approach.

We will maintain our stated course of keeping a tight focus on our core competencies. We will continue to seek growth opportunities that are complementary to and consistent with our base businesses. We will also continue to work with other utilities and pipeline companies in Canada to persuade regulatory authorities and public policy makers that we must compete in a North American capital market and we need returns on equity more closely in line with those allowed our American counterparts.

OUR EMPLOYEES

2001 was not an easy year. Our gas utility employees were frequently confronted by angry and confused customers who could not understand how their gas bills could soar so high when they had been so low for so long. At Trans Mountain there was the disruption for many of moving their households when the head office was relocated to Calgary. While a number of employees were not able to relocate, the transition was done with remarkably little disruption.

On behalf of all our shareholders, we thank all our employees who made a success of an unsettled year.

THANKS AND FAREWELL

In addition to your Chairman, two directors, Robert G. Brodie and Donald A. Carlson, will be leaving the Board following the 2002 Annual General Meeting. Both have served the Company and shareholders well. We have benefited from their sound advice and counsel reflecting their considerable business experience. Mr. Brodie has served on the Board since 1978 and Mr. Carlson since 1995. We thank them both and wish them every success in their future endeavours.

R. L. Cliff

Ronald L. Cliff
Chairman

J. M. Reid

John M. Reid
President & Chief Executive Officer

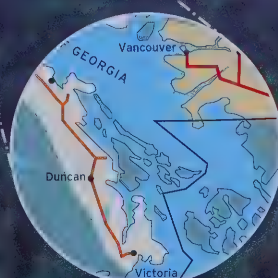
February 14, 2002

EXPANDING OUR BASE BUSINESS

We are pursuing several strategic opportunities for growing our business. Our acquisition of Centra Gas expands our gas distribution asset base by 20 per cent and enables us to take advantage of significant operational synergies. Recognizing the need for new capacity additions in the Lower Mainland, we are planning to build a new pipeline that will offer customers more choice and increase the supply of natural gas to this region. In addition, we are taking a leadership role in the transportation of production from Alberta's vast oil sands resource. The Corridor Pipeline, and our proposal to build the Bison Pipeline, will provide shippers with opportunities to move their bitumen and synthetic crude oil to market.

Significant growth lies ahead for the Athabasca oil sands of northeastern Alberta. The Corridor Pipeline and proposed Bison Pipeline bring significant value to our asset base and enable us to serve the growing needs of producers and shippers in the region.

At 493 kilometres, Corridor Pipeline will be the world's longest dedicated diluent/bitumen pipeline. This $688 million project – scheduled for completion in spring 2003 – expands our asset base and enables us to participate in developing the Athabasca oil sands.



Our acquisition of Centra Gas – the natural gas supplier to the Sunshine Coast and Vancouver Island – expands our gas distribution franchise and customer base. The harbour of Victoria – featuring the Empress Hotel – is shown above.

BC Gas Utility's proposed Inland Pacific Connector Pipeline will increase the supply of natural gas to the Lower Mainland and offer greater choice to our many customers in southern British Columbia.

GROWING OUR CUSTOMER BASE WITH THE CENTRA ACQUISITION

The acquisition of Centra Gas British Columbia — scheduled to be finalized in March 2002 — increases the scale of our natural gas utility operations and distribution service area in British Columbia.

Centra Gas delivers natural gas to 70,000 customers on Vancouver Island and the Sunshine Coast, including seven pulp mills. Since introducing natural gas service to Vancouver Island in 1991, Centra Gas has enjoyed strong customer growth, averaging 13 per cent per year between 1994 and 2000. With a penetration rate of less than 50 per cent on existing gas mains, there is opportunity for future growth of our customer base. There is also potential for development of new gas-fired power plants in addition to the Island Cogeneration Project at Campbell River served by Centra Gas.

The Centra acquisition is an excellent fit with our strategic direction and will enable us to deliver growth by expanding our base business in British Columbia. In addition to enhancing our scale of operations, it adds both operating efficiencies and a number of operational synergies. Centra's transmission system, for example, ties into BC Gas Utility lines in the Lower Mainland. The Company will also benefit by adopting the best operating practices of BC Gas Utility and Centra Gas British Columbia.

CENTRA GAS BRITISH COLUMBIA

Legend

- Centra Gas Transmission Pipelines
- Proposed Pipeline
- BC Gas Utility Ltd.
- BC Gas Utility Ltd. Distribution Service Area
- Centra Gas British Columbia Distribution Service Area

The acquisition of Centra Gas expands BC Gas' natural gas distribution business in British Columbia.

BC Gas' natural gas operations will be extended to Vancouver Island and the Sunshine Coast, following the Company's acquisition of Centra Gas British Columbia.

BUILDING A NEW PIPELINE TO BETTER SERVE OUR CUSTOMERS

At BC Gas, we're focused on meeting the needs of our customers – both now and in the future. With the successful completion of the Southern Crossing Pipeline in November 2000, we are meeting peak day demand and providing our customers with greater access to natural gas supply. While Southern Crossing was a partial solution to supply problems that led to the dramatic increase in gas costs last winter, an overall shortfall in gas supply has created higher natural gas prices in British Columbia relative to the rest of the Pacific Northwest.

As we look ahead, we recognize that additional capacity is needed in southern B.C. These capacity requirements are driven by growth in demand as well as the need for reserve capacity to ensure the wholesale markets function properly. Energy companies from B.C., Oregon and Washington are working together to minimize the risk of energy shortfalls and to meet the need for electric generation capacity and gas and electric transmission capacity.

Some of these capacity needs will be met by expansion currently underway, however, this does not address the equally pressing need to obtain alternative sources of supply. We are therefore proposing to build the Inland Pacific Connector Pipeline. Depending on the timing of new power-generation facilities in the area, the targeted in-service date of this new pipeline is November 2004.

The 246-kilometre Inland Pacific Connector Pipeline will extend the Southern Crossing Pipeline west from Oliver to the regional marketing hub in Huntingdon. The new pipeline will increase the supply of natural gas to the Lower Mainland. We estimate this project will cost $495 million.

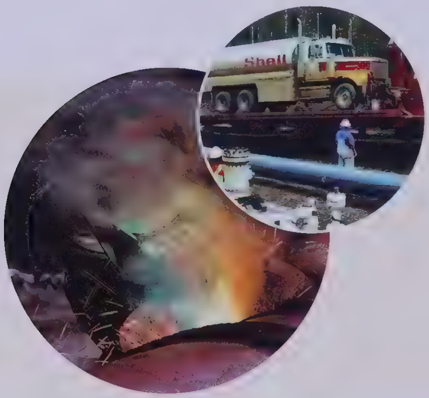
Over the past year, BC Gas Utility has held extensive discussions with local communities and First Nations groups about this project. This consultation process is building on the successful relationships established with First Nations groups during construction of the Southern Crossing Pipeline. First Nations communities are actively participating in environmental assessment for the Inland Pacific Connector Pipeline (including fisheries, forestry and traditional use studies) and we are working to ensure they will benefit from the development opportunities offered by this project.

INLAND PACIFIC CONNECTOR

Legend

- BC Gas Utility Ltd. Transmission Pipelines
- Southern Crossing Pipeline Completed Nov. 2000
- Proposed Inland Pacific Connector Pipeline
- Other Natural Gas Transmission Pipelines
- BC Gas Utility Ltd. Distribution Service Area

The proposed Inland Pacific Connector Pipeline would provide customers with greater access to natural gas supply.



CORRIDOR PIPELINE – ON TIME AND ON BUDGET
Construction of the Corridor Pipeline is nearing completion, with start-up scheduled for April 2002. Upon full operation in early 2003, the pipeline will significantly expand our petroleum transportation business. The pipeline is part of the Athabasca Oil Sands Project being developed by Shell Canada, Western Oil Sands and Chevron Canada.

ALBERTA OIL SANDS DEPOSITS

Legend

Alberta Oil Sands Deposits

Production from the Alberta oil sands is increasing rapidly, from the current 320,000 barrels per day to a forecasted 700,000 barrels per day in 2003 and 1.6 million barrels per day by 2008. Our current and proposed pipelines serve the Athabasca deposit, where 70 per cent of the total reserves of the oil sands are located.

COMPLETING CORRIDOR PIPELINE

We are nearing completion of Corridor Pipeline – a $688 million project that will add considerable value to our asset base and enable us to participate in the development of the Athabasca oil sands in northeastern Alberta. This pipeline is part of the Athabasca Oil Sands Project (AOSP) being developed by Shell Canada, Western Oil Sands and Chevron Canada.

The Corridor Pipeline project is proceeding on time and on budget. By phasing construction over a three-year period, we have benefited from significant cost savings and a reduced risk of cost overruns.

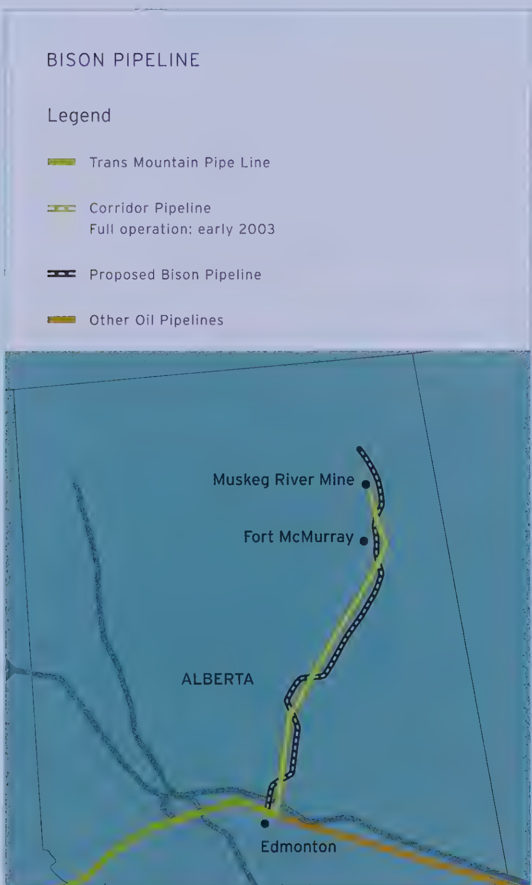
Corridor is scheduled to start up in April 2002, connecting the AOSP Muskeg River Mine north of Fort McMurray to the project's upgrader adjacent to Shell's Scotford Refinery north of Edmonton.

Corridor has long-term ship-or-pay contracts with established shippers. When completed, the 493-kilometre pipeline will be the world's longest dedicated diluent/bitumen pipeline, with an initial capacity of 220,000 barrels per day of diluted bitumen, including 155,000 barrels per day of bitumen and 65,000 barrels per day of diluent. Trans Mountain Pipe Line provided expertise to manage the design and construction of the pipeline and will act for BC Gas as its operator. Shell has announced plans to expand output of the mine by more than 40 per cent later this decade. Corridor's capacity can be expanded by adding pumping stations to handle the planned output.

We have completed the final winter construction spread of the pipeline and are particularly proud of our safety record. By ensuring that all contractors met our strict standards and followed our safety program, we achieved unparalleled safety performance for the pipeline construction industry.

PROPOSED BISON PIPELINE TO MEET NEEDS

BC Gas is committed to meeting the evolving needs of producers in the Athabasca oil sands region — an area that is undergoing significant growth. In January 2002 we announced plans for the Bison Pipeline, an $800 million, 516-kilometre pipeline that will transport bitumen from Fort McMurray to refineries and interprovincial pipeline terminals near Edmonton.



The Bison Pipeline is planned to transport heated bitumen – a hydrocarbon of high density and viscosity – from north of Fort McMurray to Edmonton.

Bison Pipeline Ltd., a wholly owned subsidiary of BC Gas, is overseeing this project and is now undertaking joint engineering and technical studies with potential shippers, including TrueNorth Energy and Petro-Canada. We plan to receive final regulatory approval in the first half of 2003 and, provided all parties decide to proceed, we can complete construction by mid-2005, matching the shippers' planned production schedule.

Bitumen is usually blended with large quantities of diluent to allow it to be shipped in a conventional pipeline like Corridor, but because Bison is being designed as an insulated pipeline, only minimal (if any) diluent will be required. The planned pipeline therefore offers many advantages to producers, as they will no longer be required to obtain diluent to transport bitumen to Edmonton. By shipping bitumen to Edmonton, they can access a larger and more price competitive market for diluent and bitumen processing, and avoid the significant cost of moving diluent between Edmonton and the oil sands area. The pipeline will also allow shippers with facilities in the Edmonton area to pursue an integrated strategy of upgrading and refining their own production.

In order to maximize the flexibility of the pipeline and meet the needs of a range of customers, Bison will be designed as a batch system. Several access points into the pipeline will enable producers to ship several grades of bitumen.

The pipeline will have an estimated capacity of 450,000 barrels per day of bitumen — almost double the planned capacity of Corridor. We will use our proven expertise in pipeline construction and operation to ensure that the Bison Pipeline is efficient and environmentally sound and that it provides shippers with a competitive toll.

STRENGTHENING OUR BASE BUSINESS

Our strategy of improving efficiencies and focusing on customers is enabling us to strengthen our base businesses of natural gas distribution and petroleum transportation. The natural gas distribution business moved to a new operations centre and reorganized its management team, creating a more focused and effective company. In order to be closer to our customers, and to better meet their needs, we have relocated our petroleum transportation headquarters to Calgary, and built a new control centre in Edmonton. These initiatives – along with negotiating a multi-year rate settlement for the natural gas distribution business and completion of the first full year of our second five-year toll incentive for the petroleum transportation business – are building a better BC Gas.

Management and employees of BC Gas Utility have moved to a new operations centre in Surrey, B.C., where they are benefiting from improved operational efficiencies.

2001 was the first year of a new five-year toll settlement between Trans Mountain and its shippers on the mainline pipeline system. This new settlement provides toll stability and certainty for shippers and incentives for Trans Mountain.

We promote the safe use of natural gas and energy conservation. Ken Ohlsson, Unifirst Production Manager (above) recently installed a heat recovery unit on the boiler at their Langley laundry operation. The change delivers significant energy savings. BC Gas is actively promoting his initiative as an example for others to follow.

In 2001, Trans Mountain moved its headquarters to Calgary, positioning the Company to take advantage of growth opportunities in the oil and gas sector.

NATURAL GAS DISTRIBUTION
We are strengthening our natural gas distribution business by increasing efficiencies, working to improve safety performance and pursuing an appropriate regulatory structure.

CREATING A STRONGER UTILITY

We are creating a more efficient and customer-focused utility. In late 2001, we reorganized our management structure to establish a management team that is dedicated to BC Gas Utility. This team is working to achieve an appropriate regulatory structure, increase efficiency, improve safety performance and build the business. Utility management and most employees are now based in the new BC Gas Utility operations centre in Surrey, B.C., enabling the sharing of knowledge and improved operational efficiencies.

The renewal process for the regulatory incentive settlement is now underway, and this agreement is planned to take effect on January 1, 2003 for both BC Gas Utility and Centra Gas. We are coordinating our regulatory settlements in the context of emerging provincial energy policy, in order to develop a new multi-year agreement encompassing BC Gas Utility and Centra Gas. Our preferred solution is a regulatory agreement that is outcome-based – focused on price and the quality of service we deliver to our customers.

During the year, the Utility successfully negotiated with unions representing employees. We signed a two-year agreement with the OPEIU and a five-year agreement with the IBEW. Both agreements are aligned with increasing our focus on meeting customer needs.

PROMOTING ENERGY EFFICIENCY

We launched several programs in 2001 in our ongoing efforts to encourage energy conservation. Energy efficiency programs contribute to a cleaner environment and reduce our gas supply costs by easing peak load requirements. These programs were well received by customers, who were very interested in reducing their energy bills and offsetting higher natural gas costs.

More than 28,000 customers took advantage of one new program offering a $25 rebate to those who had their gas furnace tuned by a qualified contractor.

For commercial and institutional customers, we introduced an energy advisory program that provides conservation and efficiency advice on a customized basis. Participants have seen encouraging reductions in natural gas use. We also offered financial assistance toward the cost of upgrading to a high-efficiency boiler.

NEW TOLL SETTLEMENT BENEFITING CUSTOMERS AND TRANS MOUNTAIN

This was the first year of a new five-year toll settlement between Trans Mountain Pipe Line and its shippers on the mainline pipeline system. Shippers and Trans Mountain are both benefiting from the settlement, which represents another step forward in the evolution of economic deregulation. This agreement provides shippers and producers with toll stability and certainty, as tolls calculated for 2001 remain in effect over the five-year term.

Under the settlement, Trans Mountain fully benefits from any realized efficiencies and savings associated with operating the pipeline system. Over the long term, reducing the costs of operating the pipeline system will provide competitive tolls for shippers on the Canadian and U.S. systems.

The new toll settlement provides Trans Mountain with incentives to increase the deliveries of crude oil. Deliveries for the year on Trans Mountain's mainline system from Edmonton, Alberta to British Columbia and Washington State were 33,270 cubic metres per day, up two per cent over 2000. Through these incentives, Trans Mountain loaded 11 crude oil tankers at its Westridge Marine Terminal, which did not constitute a significant portion of deliveries before the new settlement.

In 2001, Trans Mountain saw increased operating and cost efficiencies as a result of the major restructuring and relocation initiative undertaken in 2000. Restructuring the management and operational organization on the Trans Mountain system resulted in a 25 per cent reduction in employees assigned to Trans Mountain's activities. This was, for the most part, managed through an early retirement incentive program and reassignment of personnel to the Corridor System. Trans Mountain's headquarters were relocated to Calgary in mid-2001 to be closer to shippers and producers and to position the company to take advantage of growth opportunities in Western Canada, such as the proposed development of the Bison Pipeline. The control centre was relocated to Edmonton, and is now closer to the growth in operations in northern Alberta. When the Corridor Pipeline comes on line later this year, its operations will be managed from this new control centre.

In 2001, petroleum transportation contributed $0.71 to the Company's earnings per share, up $0.15 from the previous year.

Knowing that being close to customers is good for business, Trans Mountain moved its headquarters to Calgary this year. Keith Dunbar (left), Trans Mountain's Manager of Oil Movements and Planning talks with customer Bill Henderson, President of Tidal Energy Marketing Inc.

GROWING FROM OUR CORE COMPETENCIES

We see many opportunities to grow from our core competencies and develop new businesses that complement and strengthen our proven areas of expertise. Over the past few years we have launched several new businesses – from CustomerWorks, the largest service provider of its kind in Canada, to ENRG, the leading natural gas fueling company in North America. Although these businesses represent a small portion of the Company's total activities, they offer exciting new opportunities for earnings growth and future expansion.

With its national network of five call centres, CustomerWorks offers comprehensive customer care for utilities, municipalities and energy services companies.

Municipalities are increasingly using water meters to measure use of this valuable resource.

Under growing pressure to reduce ground air emissions, airports are a key market for ENRG.

CUSTOMERWORKS

CustomerWorks started full-scale operations on January 1, 2002 as the largest service provider of its kind in Canada, offering comprehensive customer services for utilities, municipalities and energy services companies across the country.

BC Gas owns 30 per cent of this new entity, which is operated under a limited partnership with Enbridge Inc. Through a national network of five call centres, CustomerWorks provides customer contact, billing support and meter reading for BC Gas' utility operations and Enbridge's utility and retail operations, representing a total of 3.3 million customers.

BC Gas' successful new customer information system and our Kelowna Call Centre are important components of the partnership. CustomerWorks will manage the rollout of the new customer information system to BC Gas Utility customers in the Lower Mainland as well as to future new customers. A total of 140 BC Gas employees have joined CustomerWorks, which now has more than 1,000 employees.

CustomerWorks provides a low-risk revenue stream through long-term service contracts with utilities and municipalities and was immediately profitable on start-up. By taking advantage of the strength and economies of scale behind CustomerWorks, utilities, municipalities and retail energy companies can focus on their core business while providing improved customer service at a lower cost.

CustomerWorks is actively pursuing growth opportunities to increase the number of customers served across Canada.

BCG SERVICES

BCG Services, a wholly owned subsidiary of BC Gas, is focused on operating water and wastewater utility systems. The market for water services continues to grow as municipalities and districts look for expertise, security and savings in managing their water systems. Over the past year, we secured three long-term contracts, strengthening our market position as a full-service water services company in British Columbia and Alberta.

In 2001, we signed a three-year water meter reading contract with the City of Surrey. In addition, we were selected to design and implement their voluntary water meter installation program. We believe our packaged approach to managing water – which includes meter reading and installation, marketing and public relations, and conservation education and retail conservation products – gives us a distinct market advantage and is an excellent example of using our core competencies to expand into other service areas.

In conjunction with CustomerWorks, we started a five-year contract providing customer care and

BCG Services provides water distribution specialty utility services for municipalities and developers. BCG Services' President Brett Hodson (left) and Director of Major Contracts Ron Bowman (right) consult with Mike Darbyshire, Sewer and Water Systems Manager for the City of Surrey.

meter reading services for water and electricity for the City of Kelowna in January 2002. With our economies of scale, we offer clients cost-effective packaged solutions – allowing them to focus on better serving their customers.

During 2001, we upgraded and expanded the existing wastewater treatment plant for Panorama Resort in eastern British Columbia to meet the year-round needs of the resort's hotels and condominiums. BCG Services owns and operates the resort's wastewater treatment plant and has a renewable 25-year contract.

Last year we strengthened our skills and capabilities in managing water and wastewater systems, expanded the range of our services and arranged exclusive distribution rights to certain pump lines.

In 2001, we established a relationship with California Water Services Group, the largest full-service water services utility in California and the third-largest in North America. This relationship will help us strengthen our service and marketing capabilities as we grow in B.C. and Alberta.

BC GAS INTERNATIONAL

BC Gas International provides engineering and consulting services predominantly in the Persian Gulf, where we are involved in two major projects.

In the United Arab Emirates, we are working with our local partner, S.S. Lootah International, to complete the $60-million second phase of the first natural gas distribution system in the Gulf region. On completion in March 2002, this system will extend natural gas supply to an additional 33,500 customers in the City of Sharjah. BC Gas International successfully completed the first phase in 2000. The third phase of the project should start in April 2002.

In Oman, Canadian Energy Services LLC – a company jointly owned by BC Gas International, Enbridge Technology Inc. and OHI Petroleum & Energy Services LLC – was awarded a $42 million contract to operate and maintain natural gas transmission facilities owned by Oman Gas Company. The existing 800-kilometre transmission system delivers gas to industrial customers and power plants. The contract includes a 1,000-kilometre pipeline expansion to be completed in late 2002.

We are looking to develop other gas distribution projects in the Gulf region as local governments replace the use of petroleum products with indigenous natural gas supplies.

ENRG

A leader in clean transportation, ENRG is the largest natural gas fueling company in North America. ENRG was formed in 2001 with the merger of BCG eFuels and Pickens Fuel Corp. BC Gas owns 56 per cent of ENRG, which is based in California.

ENRG has a solid presence in British Columbia, Ontario, Arizona and California. We own and operate 90 fuel stations serving over 25,000 vehicles. Our focus is on meeting the needs of fleet customers in the taxi, waste removal, transit and airport industries. In November, we were awarded the contract to provide natural gas fuel for Foothill Transit, one of the largest municipal transit operators in Los Angeles County. Under a long-term lease agreement, ENRG will design, build, maintain and own the compressed natural gas fueling station.

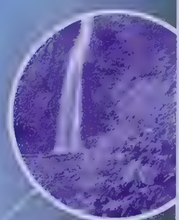
In December, we completed construction of the Sky Harbor fueling station at Phoenix airport – the largest public-access natural gas vehicle (NGV) fueling station in North America. With the addition of Sky Harbor, ENRG now owns and operates NGV fueling stations at nine airports. Airports are a key market as they are under pressure to reduce air emissions by ground vehicles.

We are also focused on diesel-reliant heavy-duty fleets. Continuing regulatory pressure to reduce diesel fuel use offers opportunities for the cleaner and more economical alternative of natural gas. ENRG has an agreement with Ford Motor Company to support its marketing of alternative fuel vehicles.

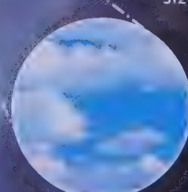
WORKING WITH OUR COMMUNITIES

At BC Gas we support the well-being of local communities through a wide range of initiatives and partnerships. We value the responsibilities that come with being a corporate citizen. We are committed to continuously improving the health, safety and environmental performance of our operations.

Increasing customer awareness of the safe use of natural gas is the focus of ongoing programs at BC Gas.



BC Gas Utility is one of the lowest greenhouse gas emitting distribution companies of its size in Canada.



Willow, cottonwood and dogwood shrub seedlings were grown by First Nations especially for the Southern Crossing revegetation program. The plantings will [illegible] important to a variety of [illegible] species.

Trans Mountain has a number of programs in place to ensure environmental protection, superior safety performance and pipeline integrity.

BC Gas is proud to support the University of Northern British Columbia's distance learning program. Left to right: Dr. Charles Jago, President of UNBC, Randy Jespersen, President of BC Gas Utility and Tom Berekoff, Director of UNBC's Office of University Development.

WORKING WITH OUR COMMUNITIES

We believe in the importance of establishing and maintaining strong relationships with the municipalities we serve. Forging business partnerships with local governments ensures that joint infrastructure projects run smoothly and with fewer disruptions for community members. For example, we help municipalities develop their official community plans and emergency response plans.

We are taking steps to enhance relationships with municipal governments by renewing franchise agreements and working to resolve issues related to gas and water operations in an increasingly complex business environment. These initiatives make it easier for municipalities to plan their growth in an efficient way.

In 2001, we combined our commitment to education and First Nations initiatives by pledging $213,750 over a five-year period to the Chinook Program at the University of British Columbia's Faculty of Commerce. This innovative program offers First Nations students an undergraduate education in management and entrepreneurship that is tailored to their interests and specific needs.

We are also committed to supporting healthcare initiatives. Over a six-year period, BC Gas and Trans Mountain Pipe Line are contributing $100,000 to the BC Cancer Foundation. BC Gas Utility has also pledged $40,000 to the Vancouver General Hospital and UBC Hospital Foundation over five years, beginning in 2001.

Employees at BC Gas Utility continued to demonstrate their strong community involvement by raising more than $316,000 for United Way agencies in 2001. At Trans Mountain Pipe Line, this year's United Way campaign saw a significant increase in employee participation and Trans Mountain received the Gold Award from the Calgary United Way for campaign excellence.

REDUCING GREENHOUSE GAS EMISSIONS

In March 2002 we were honoured to receive the Leadership Award for the Oil and Gas Pipelines and Distribution sector from Canada's Climate Change Voluntary Challenge and Registry (VCR). This national program is designed to encourage and track voluntary reductions of greenhouse gas emissions. BC Gas was selected by an independent judging panel for its commitment, action and leadership in this area.

In addition, for the third consecutive year, BC Gas was awarded gold level reporting status from the VCR, recognizing our use of specific measures and targets in our reporting.

BC Gas Utility is recognized as one of the lowest greenhouse gas emitting distribution companies of its size in Canada. In fact, despite large increases in both the number of customers served and natural gas volumes delivered, we have reduced emissions

from our operations to below 1990 levels. Our two key performance indicators of emissions per unit of production and emissions per customer are now 10 and 25 per cent respectively below what was achieved in 1990.

These results have been attained through a combination of operational efficiencies, equipment selection and offset project investment. We are committed to ongoing efforts to manage our emissions and continue to look for new greenhouse gas reduction measures within our operations, to support the natural gas industry's research and to pursue greenhouse gas offset project solutions.

MINIMIZING SULPHUR CONTENT IN TRANSPORTED GASOLINE

To meet new federal government regulations that will come into effect in January 2005, Trans Mountain Pipe Line is chairing a joint task force studying the impact of reduced sulphur in gasoline. The maximum allowable sulphur content in gasoline will be 30 parts per million, as compared to the current range of 150 to 300 parts per million. When gasoline is shipped through the Trans Mountain pipeline, it currently picks up 30 to 70 parts per million total sulphur from other batched products. The goal is to transport gasoline with a sulphur pick-up that meets the new government regulations. The joint task force is confident it can achieve the new target.

FOCUSING ON CUSTOMER AND EMPLOYEE SAFETY

BC Gas is committed to safety. One continuing initiative is to increase customer and public awareness of the risks associated with the use of natural gas and the actions customers can take to prevent an incident. Our communication efforts over the past year focused on improving natural gas safety awareness among our customers. We integrated both safety and energy-saving messages to ensure that customers who were implementing energy-saving initiatives were doing so in a safe manner. Other programs in 2001 reminded customers of the actions to take if they noticed a gas odour and included tips on appliance maintenance, reminders to "Call Before You Dig", and guidelines about carbon monoxide safety.

Employee safety is a priority. In 2001, our lost-time injuries increased for the first time in five years. We are taking this matter very seriously and are currently investigating these incidents so we can better understand their root causes – and prevent further incidents of this type. In 2002 we will improve our injury management process and will actively involve those departments that have experienced time-loss injuries. Our goal is to continuously improve our safety performance relative to our peer group.

Trans Mountain Pipe Line employees reported no lost-time injuries in 2001. There was one minor reportable spill related to storage tank corrosion.

BUILDING RELATIONS WITH FIRST NATIONS

We understand the importance of fostering and enhancing relationships with the First Nations communities located throughout our service area. We are working at the grassroots level with bands to ensure that First Nations are beneficiaries in their traditional territories and are able to fully participate in developing business opportunities.

BC Gas Utility has been working with First Nations groups to explore ways of providing training and education so they have the skills and knowledge needed to participate in future projects, including the proposed Inland Pacific Connector Pipeline. By building capacity and skills within First Nations bands, BC Gas is helping to ensure they will be well positioned to pursue development opportunities and be strong business partners.

As with the Corridor Pipeline, the proposed Bison Pipeline will pass through the traditional lands of First Nations and Metis communities in northern Alberta. Many members of these communities were employed in the construction of the Corridor Pipeline and we anticipate their active involvement in development of the proposed Bison Pipeline.

FINANCIAL PERFORMANCE

BC Gas continued to deliver on its strategic initiatives and financial targets in 2001. Operating results improved in both the natural gas distribution and petroleum transportation businesses and new business initiatives were pursued throughout the Company's core businesses. BC Gas' key financial objectives are earnings per share growth of 6 per cent per year and a return on common equity of 12 per cent before non-recurring items. BC Gas has achieved these objectives over the past four years.

2001 HIGHLIGHTS

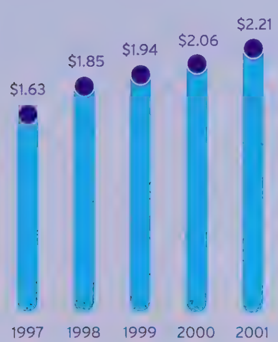
- Agreed to acquire Centra Gas B.C., extending BC Gas' natural gas distribution operations to Vancouver Island and the Sunshine Coast.
- Arranged long term debt and equity financing for the Centra Gas B.C. acquisition on attractive terms.
- Continued construction on the Corridor Pipeline; the project is on time and on budget.
- Achieved higher revenues and reduced operating costs in the first year of Trans Mountain Pipe Line's new incentive toll settlement.
- Merged BCG eFuels with Pickens Fuel to form the largest natural gas fuel provider for vehicles in North America.
- Created CustomerWorks, a joint venture with Enbridge to provide full service customer management solutions to utilities, municipalities and retail energy companies across Canada.

SHAREHOLDER RETURN

Over the past five years, the compound annual rate of return on BC Gas shares, including dividends, was 14.9 per cent.*

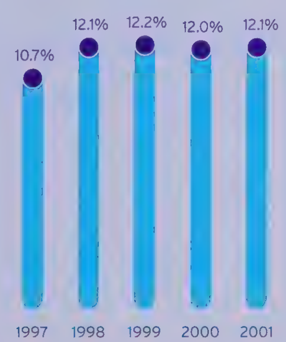
*Based on an investment of $100 at December 31, 1996, assuming reinvestment of dividends.

EARNINGS PER SHARE BEFORE NON-RECURRING ITEMS



Earnings per share before non-recurring items were $2.21 in 2001, up 7 per cent from 2000.

RETURN ON COMMON EQUITY



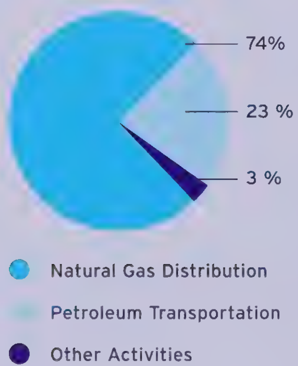
In 2001, BC Gas again achieved its targeted return on equity of 12 per cent.

MANAGEMENT DISCUSSION AND ANALYSIS

This discussion and analysis is a review of the operating results, business risks, financial condition and outlook for BC Gas Inc. (BC Gas or the Company). This discussion should be read in conjunction with the consolidated financial statements of the Company and related notes.

TOTAL ASSETS

Total assets at year-end 2001 were $3,705.7 million.



BC Gas' natural gas distribution and petroleum transportation businesses represent 97% of the Company's assets.

BUSINESS SEGMENTS OF BC GAS

Natural Gas Distribution

The Company's natural gas distribution operations consist primarily of BC Gas Utility Ltd. (BC Gas Utility or the Utility) and several small related utility operations. BC Gas Utility is the largest distributor of natural gas in British Columbia, serving 767,000 customers in more than 100 communities. BC Gas Utility provides transmission and distribution services to its customers, and obtains gas supplies primarily on behalf of residential and commercial customers, making the Utility the largest single buyer of natural gas in the province. Gas supplies are sourced primarily from northeastern British Columbia and, through the Southern Crossing Pipeline, from Alberta. Major areas served are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of the province. The Company has also agreed to acquire Centra Gas British Columbia Inc. (Centra Gas BC) and Centra Gas Whistler Inc. (collectively, Centra Gas) from Westcoast Energy Inc.

Petroleum Transportation

BC Gas' petroleum transportation operations are carried out by Trans Mountain Pipe Line Company Ltd. (Trans Mountain), which owns and operates a pipeline system transporting crude oil and refined products from Edmonton, Alberta to Burnaby, British Columbia. The pipeline of a U.S. subsidiary delivers Canadian crude oil to several refineries in Washington State. In addition, Trans Mountain owns and operates a marine terminal in the Port of Vancouver and a jet fuel pipeline to a storage system at Vancouver International Airport. Through Corridor Pipeline Limited, the Company is constructing a dual pipeline system which will transport diluted bitumen and diluent between Fort McMurray and Edmonton, Alberta at an estimated cost of $688 million.

Other Activities

BC Gas has other activities, which include non-regulated energy and utility businesses as well as corporate interest and administration charges. The non-regulated businesses include water services and international consulting. The majority of these businesses are direct subsidiaries of BC Gas.

EARNINGS PERFORMANCE

The contribution to earnings applicable to common shares of each segment is as follows:

Years ended December 31 (In millions of dollars except per share amounts)	**2001**	**Per Share**	2000	Per Share
Natural gas distribution	**$ 67.8**	**$ 1.77**	$ 58.7	$ 1.53
Petroleum transportation	**27.3**	**0.71**	21.3	0.56
Other activities	**(10.5)**	**(0.27)**	(1.2)	(0.03)
Earnings before non-recurring items	**84.6**	**2.21**	78.8	2.06
Non-recurring items	**–**	**–**	30.0	0.78
Earnings applicable to common shares	**$ 84.6**	**$ 2.21**	$108.8	$ 2.84

BC Gas discloses earnings before non-recurring items in order to assist investors in evaluating which components of the Company's earnings are likely to be sustainable in future years. For this purpose, the Company identifies non-recurring items, which are material gains and losses that, in management's opinion, arise from events or circumstances that are not expected to occur on a regular basis. Earnings before non-recurring items does not have any standardized meaning prescribed by generally accepted accounting principles, and therefore may not be comparable to similar measures presented by other Canadian issuers of securities.

Non-recurring items of $0.78 per share in 2000 are comprised of three items. A gain of $0.76 per share arose from income tax benefits associated with NW Energy, which the company monetized in 1999. A gain of $0.22 per share resulted from the effect of income tax rate reductions in calculating future income tax liabilities. Offsetting these benefits is an after-tax charge of $0.20 per share associated with restructuring costs at Trans Mountain.

Earnings before non-recurring items were $84.6 million in 2001 compared to $78.8 million in 2000. An analysis of the increase in earnings is as follows:

In millions of dollars	
Earnings applicable to common shares for 2000	$108.8
2000 non-recurring items	
Income tax benefits from NW Energy	29.0
Gain from future income tax rate reductions	8.5
Restructuring costs	(7.5)
Earnings before non-recurring items for 2000	78.8
Natural Gas Distribution	
Earnings from higher capital expenditures	11.2
Lower allowed return on common equity in 2001	(1.8)
Other items	(0.3)
Petroleum Transportation	
Higher throughput and other items	6.0
Other Activities	
Financing costs associated with new investments and other items	(7.7)
Adverse economic conditions and integration costs	(1.6)
Earnings applicable to common shares for 2001	$ 84.6

NATURAL GAS DISTRIBUTION

Contribution to Earnings

In millions of dollars	2001	2000
Revenues	**$1,420.3**	$1,085.4
Operating expenses		
Cost of natural gas	**931.8**	658.4
Operation and maintenance	**136.3**	124.4
Depreciation and amortization	**75.7**	67.1
Property and other taxes	**41.9**	33.7
	1,185.7	883.6
Operating income	**234.6**	201.8
Financing costs	**126.1**	96.7
Earnings before income taxes and non-controlling interest	**$ 108.5**	$ 105.1

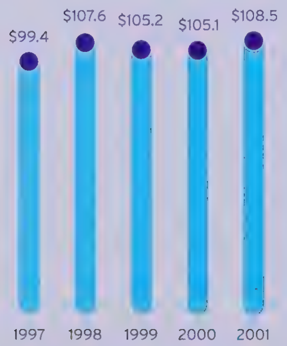
Revenues

Revenues from natural gas distribution increased to $1,420.3 million during 2001 from $1,085.4 million in 2000. Revenues are set to recover the Utility's cost of service, the largest component of which is the cost of natural gas. In 2001, revenues were higher primarily as a result of increases in the cost of natural gas as well as increases in other operating and financing costs associated with increased rate base, all of which are flowed through into customer rates.

During 2001, 4,977 new customers were added, bringing the total number of gas utility customers to 767,855 at year-end. These customer additions were mainly in the heating market for new single-family houses. The rate of customer additions decreased from 2000, when 7,495 new customers were added, as a result of weaker economic conditions as well as the termination of service for some customers for non-payment.

Industrial sales service decreased by 2,828 terajoules while transportation volumes decreased by 2,806 terajoules from the previous year. The Utility earns approximately the same margin regardless of whether a customer contracts for sales or transportation service. The net reduction in industrial volumes reflected fuel switching by industrial customers who have dual-fuel capability as well as reduced energy consumption as market prices for natural gas peaked in early 2001.

NATURAL GAS DISTRIBUTION
Earnings before Income Taxes and Non-Controlling Interest
($ millions)



Earnings in 2001 benefited from the completion of the Southern Crossing Pipeline.

Expenses

Expenses for natural gas distribution include the cost of natural gas, operation and maintenance expenses, depreciation and amortization, and property and other taxes. Total operating expenses were $1,185.7 million in 2001 compared with $883.6 million in 2000.

The cost of natural gas amounted to $931.8 million in 2001 compared with $658.4 million in 2000. The increase in the cost of gas reflects a dramatic increase in the market price of natural gas throughout North America. These higher market prices were reflected in an increase in the price of natural gas purchased by the Utility on behalf of its customers, which is flowed through into customer rates without profit.

Operation and maintenance expenses increased to $136.3 million in 2001 from $124.4 million in 2000. This increase was due largely to costs associated with new plant in service, including the Southern Crossing Pipeline.

Increased investment in gas plant in service resulted in depreciation and amortization expense rising to $75.7 million in 2001 from $67.1 million in 2000. Growth in the asset base of the Company and higher property tax rates resulted in property and other taxes increasing by $8.2 million to $41.9 million in 2001.

Financing costs increased to $126.1 million in 2001 from $96.7 million in the previous year as a result of higher debt balances due to rate base growth and the refinancing of $75 million of preferred shares with long-term debt in October 2000, offset in part by lower interest rates.

Regulation and Rates – BC Gas Utility

BC Gas Utility is regulated by the British Columbia Utilities Commission (the BCUC), which approves rates for services and issues certificates for the construction of facilities. Traditionally, rates have been set using the rate base and rate of return or cost of service approach to utility regulation. Since 1996, however, incentive-based regulation has been incorporated into the rate setting process in order to enhance value to customers and provide opportunities for enhanced returns to shareholders.

The Utility's rates are based on estimates of a number of items, such as natural gas sales, cost of natural gas and interest rates. In order to manage the risks associated with some of these estimates, a number of regulatory deferral accounts are in place. The two most significant deferral accounts relate to the risks of use per customer and the cost of natural gas. Use per customer may change as a result of warmer or colder weather, or in response to changes in the price of natural gas. The cost of natural gas purchased by the Utility on behalf of its customers varies with changes in market prices for the commodity. These changes are reflected in customer rates through quarterly rate setting adjustments.

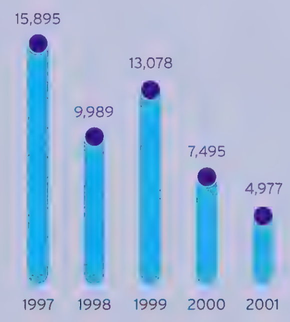
The deferral accounts for use per customer and cost of natural gas (which are also referred to as the rate stabilization accounts) reduce the Utility's earnings exposure to these risks by deferring any variances between projected and actual gas consumption and gas costs, and refunding or recovering those variances in rates in subsequent periods. Variances in usage by large volume, industrial transportation and sales services are not covered by these deferral accounts as their usage is less likely to be affected by weather. As a result of these deferral accounts, changes in reported revenues from year to year are caused mainly by changes in gas costs and other components of the Utility's cost of service, including the allowed return on equity, which are recovered in customer rates. Changes in volumes of gas sold to residential and commercial customers due to weather or other factors have a less significant impact on reported revenues.

Due to the recovery of deferral account balances in rates in 2001, offset in part by warmer than normal weather during 2001, the balances receivable from customers under the rate stabilization accounts decreased from $150.1 million as at December 31, 2000 to $147.7 million as at December 31, 2001. The impact of warmer than normal weather and the demand response to higher gas prices resulted in an increase in the use per customer deferral account. Warmer weather also reduced the rate at which the gas cost deferral account balance was recovered.

In February 2001, the BCUC issued guidelines for quarterly calculations to be prepared by the Utility to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas and ensure that gas cost rate stabilization account balances are recovered on a timely basis. Based on these guidelines, BC Gas reduced rates by approximately 11% effective October 1, 2001, and reduced rates again by approximately 5% effective January 1, 2002. The recovery of these deferral account balances is approved by the BCUC.

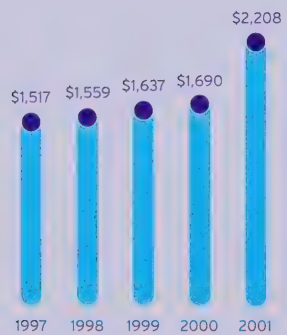
Short-term and long-term interest rate deferral accounts have also been in place to absorb interest rate fluctuations. The Utility's interest deferral accounts effectively locked in the cost of short-term funds attributable to regulated assets at 6.5% during 2001, as compared to 6% in 2000. As a result of the withdrawal of the Utility's 2002 Revenue Requirement Application (see 2002 Revenue Requirement Application on page 31), the Utility is at risk for interest rate fluctuations during 2002.

NATURAL GAS DISTRIBUTION
Customer Additions



Reduced customer additions in 2001 reflected slower economic growth.

NATURAL GAS DISTRIBUTION
Rate Base
($ millions)



Rate base increased significantly with the completion of the Southern Crossing Pipeline.

Allowed Return on Equity (ROE)

The Utility's 2001 allowed ROE of 9.25% was determined based on the BCUC formula that applies a risk premium to a forecast of long-term Government of Canada bond yields. The decrease from 9.50% in 2000 was a result of a decrease in forecast long-term bond yields. During 2001, the BCUC amended the formula such that the ROE is rounded to the nearest 0.01%, instead of the previous practice of rounding to the nearest 0.25%. For 2002, the application of the ROE formula would have set the Utility's allowed ROE at 9.13%, reflecting lower forecasted long-term bond yields compared to the 2001 ROE calculation. However, the withdrawal of the Utility's 2002 Revenue Requirement Application meant that the ROE formula was not applied to the Utility's 2002 rates.

1998-2001 Revenue Requirement Settlement

In June 1997, the Utility and other interested parties reached a negotiated settlement to set the revenue requirements for the Utility for the years 1998-2000, which was approved by the BCUC on July 23, 1997. During 2000, BC Gas negotiated a one year extension of the 1998-2000 settlement with customer representatives and other stakeholders. The one year extension was approved by the BCUC on May 4, 2000.

The key points of the settlement and extension were as follows:

- Targets were set for productivity gains in operation and maintenance costs of 2% in each of 1998 and 1999, 3% in 2000 and 1% in 2001. To the extent that these productivity targets were exceeded, the Utility had the opportunity to earn higher returns on equity. Restructuring costs of up to $3 million associated with achieving these productivity targets were deferred and recovered in customer rates. By implementing a restructuring program and other initiatives, the Utility took steps to reach and exceed these productivity targets in each year of the settlement.
- New incentives for demand side management activities and capital expenditure efficiency were made available. To the extent that demand side management programs exceed targets, and to the extent that unit costs of certain classes of capital expenditures are lower than the allowed level, the Utility had opportunities to earn higher returns. These incentives did not have a material impact on earnings.
- An earnings sharing mechanism was incorporated whereby variances in achieved return on equity from that allowed by the BCUC in a given year were to be shared equally with customers. Earnings from the established incentive programs were not included in this earnings sharing mechanism. This incentive has resulted in significant positive benefits for both customers and shareholders.
- The ratio of overheads capitalized was reduced from 22.5% of gross operation and maintenance costs in 1997 to 20% in 1998 and 1999, and to 16% in 2000 and 2001.
- The allowed common equity component remained at 33% of capitalization, and $150 million of outstanding first preference shares were redeemed and refinanced with long-term debt in 1999 and 2000.
- Through an annual review process, rates for each following year were adjusted to reflect projected changes in factors such as customer growth, industrial revenues, cost of natural gas, interest rates and taxes.

In addition to the incentives noted above, the Gas Supply Mitigation Incentive Plan (which provides an incentive for the Utility to reduce gas supply costs to customers) continued through the term of the 1998-2001 Revenue Requirement Settlement.

2002 Revenue Requirement Application

Given the pending expiry of the 1998-2001 Revenue Requirement Settlement, BC Gas initiated discussions with a number of stakeholders to develop an incentive regulatory arrangement to take effect in January 2002. As a result of this process, a 2002 Revenue Requirement Application was filed.

In October 2001, the Company announced its proposed acquisition of Centra Gas, which if completed, will likely have implications for BC Gas Utility and Centra Gas. Centra Gas B.C. is also operating under its own incentive regulatory arrangement, which expires at the end of 2002. In addition, the B.C. provincial government is undertaking a review of provincial energy policy, which is expected to be complete in 2002. In light of these developments, the Utility, with the support of a number of customer representatives, withdrew its 2002 Revenue Requirement Application.

As a result of the withdrawal, the Utility's distribution rates will remain at 2001 levels during 2002, although the deferral accounts for use per customer and natural gas costs will remain in effect. During 2002, the Company intends to work with stakeholders to develop an enhanced incentive regulatory arrangement to take effect in 2003 that reflects the acquisition of Centra Gas, more closely aligns the interests of customers with shareholders and provides the Company with greater incentives to create value for customers and the opportunity for enhanced returns for shareholders.

Unbundling

Over the past several years, the Company, the BCUC and a number of interested parties have been exploring options to provide increased customer choice to residential and smaller commercial users for their natural gas commodity purchases. Currently, these customers can only purchase their gas supplies from BC Gas. BC Gas is working with stakeholders to ensure that unbundling proceeds in a manner that adds value for customers without exposing the Company and its customers to additional risk. The Company does not anticipate that the introduction of these arrangements will have a material impact on the Company's financial results.

Acquisition of Centra Gas

On October 22, 2001 the Company entered into an agreement to acquire all of the outstanding shares and inter-corporate debt of Centra Gas British Columbia Inc. and Centra Gas Whistler Inc. from Westcoast Energy Inc. (the Acquisition). The Acquisition will be satisfied by a payment of $310 million cash (subject to adjustments) at closing and a $52 million deferred payment, payable on December 31, 2011, or sooner if Centra Gas B.C. realizes revenues from transportation contracts with power generating plants that may be constructed in Centra Gas B.C.'s service area.

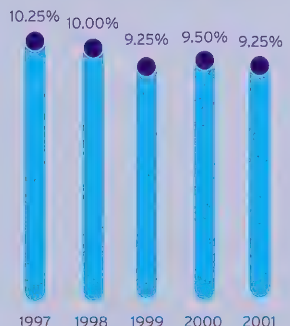
Centra Gas B.C. currently provides natural gas to 70,000 homes and businesses and seven pulp mills on Vancouver Island and the Sunshine Coast. The acquisition of Centra Gas B.C. will expand BC Gas' natural gas distribution asset base by approximately 20%. The purchase is subject to governmental approval and is expected to be finalized in early March 2002.

Business Risks

Regulatory Treatment

Through the regulatory process, the BCUC approves the return on equity which the Utility is allowed to earn, in addition to various other aspects of the Utility's operation. Fair regulatory treatment that allows the Utility to earn a risk adjusted rate of return comparable to that available on alternative investments is essential for ongoing success.

NATURAL GAS DISTRIBUTION
Allowed Return on Equity
(percent)



The allowed return on equity is linked to long-term interest rates.

Long-Term Competitiveness

The unprecedented increase in the market price of natural gas in 2000 significantly eroded the competitive advantage of natural gas relative to alternative sources of energy, notably electricity, in British Columbia. The reductions in market prices and customer rates since that time have restored natural gas' competitive advantage. However, because electricity prices in British Columbia continue to be set based on the cost of production, rather than based on market forces, they have remained artificially low. Over time, these pricing signals may distort energy use decisions by British Columbia consumers.

Even at the price levels in effect in early 2001, existing residential customers of the Utility did not generally find it economical to switch to electricity. However, customers across most customer categories reduced gas consumption through energy efficiency measures and, in the case of certain industrial customers, fuel switching. Fluctuations in use per residential and commercial customer, whether arising from weather or price levels, are deferred and recovered in customer rates and have no earnings impact on the Company. In an order dated December 28, 2000, the BCUC also noted that BC Gas Utility could apply for regulatory relief should industrial margins fall significantly below forecast levels. BC Gas Utility did not apply for such relief during 2001.

Customer Additions

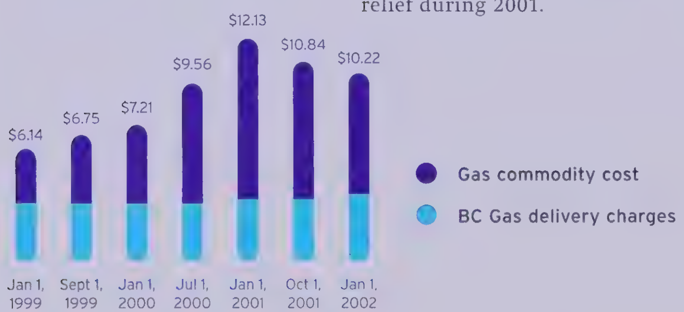
New customer additions at BC Gas Utility are typically a result of population growth and new housing starts, which are affected by the state of the provincial economy. The increases in the cost of natural gas over the past two years have also had a negative impact on the choice of natural gas for new construction. The Company is optimistic that recent reductions in the price of natural gas, combined with an eventual economic recovery in British Columbia, will have a positive effect on customer additions in the future.

Gas Supply

By successfully bringing the Southern Crossing Pipeline into service, BC Gas has improved the security and competitiveness of the gas supply arrangements in place for BC Gas' customers. To the extent possible, BC Gas Utility has also attempted to minimize gas supply and price risk through the use of long-term transportation, storage and supply contracts, hedging instruments and a diverse supply portfolio.

However, market prices in late 2000 and early 2001 have demonstrated that insufficient pipeline capacity exists to serve the increasing demand for natural gas in B.C. and the U.S. Pacific Northwest that has arisen from heating requirements and gas-fired electricity generation. In addition, BC Gas continues to be dependent on a limited selection of pipeline and storage providers, particularly in the Vancouver-Lower Mainland service area where the majority of BC Gas Utility's core market customers are located. BC Gas is actively exploring opportunities to cost-effectively expand pipeline capacity to the Lower Mainland through initiatives such as the Inland Pacific Connector Project, a proposal to extend the Southern Crossing Pipeline from Oliver (in the interior of British Columbia) to the regional natural gas trading hub of Sumas, near Vancouver.

BC GAS UTILITY LTD.
Average Residential Charge
(dollars per Gigajoule)



Reductions in market prices for natural gas have allowed BC Gas to reduce customer rates twice since October 2001.

PETROLEUM TRANSPORTATION

Contribution to Earnings

In millions of dollars	2001	2000
Revenues	**$143.1**	$132.5
Operating expenses		
Operation and maintenance	**46.5**	47.0
Depreciation and amortization	**16.4**	17.7
Property and other taxes	**18.6**	18.1
	81.5	82.8
Operating income	**61.6**	49.7
Financing costs	**13.5**	15.0
Earnings before restructuring costs and income taxes	**$ 48.1**	$ 34.7

Revenues

Revenues from petroleum transportation operations increased to $143.1 million in 2001 from $132.5 million in 2000 as a result of higher Canadian and U.S. delivery volumes in 2001 compared to 2000. Canadian mainline deliveries averaged 33,270 cubic metres per day (m^3/day) in 2001 compared to 32,533 m^3/day in 2000. U.S. mainline deliveries averaged 11,671 m^3/day in 2001 compared to 10,365 m^3/day in 2000. As was the case in 2000, throughput levels in 2001 were influenced by strong refined product margins on the West Coast and by favourable crude oil price differentials between Canadian and alternate offshore supply sources.

As discussed under Regulation, Trans Mountain's Canadian mainline was subject to a regulatory settlement that mitigated the impact of variations in throughput volumes on earnings. However, the U.S. pipeline in Washington State is not subject to the same regulatory arrangements, and fluctuations in U.S. mainline throughput have a direct impact on petroleum transportation revenues and earnings.

Expenses

Operation and maintenance expenses decreased from $47.0 million in 2000 to $46.5 million in 2001. This reflected the reduction in operating costs achieved under the restructuring undertaken by Trans Mountain, offset in part by higher fuel and power costs associated with higher throughput.

Property and other taxes increased from $18.1 million in 2000 to $18.6 million in 2001 as a result of higher property tax rates. Depreciation expense decreased from $17.7 million in 2000 to $16.4 million in 2001 as a result of revisions to the expected useful life of plant in service. Financing costs in 2001 were $13.5 million, compared to $15.0 million in 2000 as a result of lower interest rates.

Regulation

The National Energy Board (the NEB) regulates the Canadian portion of Trans Mountain's crude oil and refined products pipeline system. The NEB authorizes pipeline construction and establishes tolls and conditions of service. Traditionally, rates have been set using the historical cost rate base and a rate of return.

In 1995, Trans Mountain and shipper representatives reached a negotiated agreement that was approved by the NEB. The 1996-2000 Incentive Toll Settlement determined Trans Mountain's revenue requirement, and resulting tolls, over a five-year period which ended on December 31, 2000.

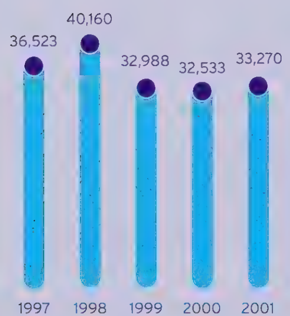
In November 2000, Trans Mountain and shipper representatives reached a negotiated agreement to determine Trans Mountain's tolls for the period 2001-2005. The settlement was approved by the NEB on March 22, 2001 to take effect as of January 1, 2001.

The 2001-2005 incentive toll settlement fixes tolls on Trans Mountain's Canadian mainline for the term of the settlement as long as throughput remains within a band of 28,500 to 32,000 m^3/day. Tolls have been set using a base throughput level of 30,000 m^3/day. Any revenue shortfalls arising from annual throughput levels below 28,500 m^3/day are recovered

PETROLEUM TRANSPORTATION
Earnings before Restructuring Costs and Income Taxes
($ millions)

Earnings increased in 2001 as a result of higher throughput and incentives under Trans Mountain's new toll settlement.

PETROLEUM TRANSPORTATION
Canadian mainline
(including U.S. mainline)
(cubic metres per day)



The 2001 to 2005 incentive toll settlement uses a base throughput of 30,000 m^3/day.

from the shippers. Incremental revenues arising from annual throughput above 32,000 m^3/day are shared 50/50 between Trans Mountain and the shippers. The fixed tolls do not escalate with inflation unless Canadian inflation rates increase above 3.5%, and Trans Mountain keeps all of the benefits achieved through productivity initiatives and operating efficiencies.

The 2001-2005 incentive toll settlement also provides for two incentive tolls which will provide toll reductions for specified types of traffic on Trans Mountain's pipeline system. The incentive tolls apply to export volumes of oil loaded over the Westridge Dock in Vancouver harbour and to movements of an alkalyte material which is expected to replace MTBE.

The toll charged for the U.S. pipeline in Washington State falls under the jurisdiction of the Federal Energy Regulatory Commission (FERC). Regulation by FERC is on a complaint basis. There were no complaints in 2001.

Tolls for the jet fuel pipeline system are regulated by the BCUC. In 1997, Trans Mountain conducted negotiations with the principal shippers on the jet fuel pipeline system. Those negotiations resulted in an agreement to determine the jet fuel pipeline revenue requirement in a manner substantially similar to the 1996-2000 incentive toll settlement for the crude oil and refined products pipeline. The agreement began to operate for a five-year period on January 1, 1998.

Corridor Pipeline

Trans Mountain and the Company have entered into an agreement with Shell Canada Limited (Shell), Chevron Canada Resources Limited and Western Oil Sands Inc. for the construction and operation of the Corridor pipeline system. Corridor Pipeline Limited (Corridor) has been established as a direct subsidiary of the Company to own and operate this system.

The Corridor pipeline system will provide for the pipeline transportation of diluted bitumen produced at the Muskeg River Mine located approximately 70 km north of Fort McMurray, Alberta to a heavy oil upgrader that Shell and its partners plan to construct adjacent to Shell's existing Scotford Refinery near Edmonton, Alberta, a distance of approximately 453 km. A smaller diameter parallel pipeline will transport recovered diluent from the upgrader back to the mine. Corridor will also construct two additional pipelines, each 43 km in length, to provide pipeline transportation between the proposed Scotford Upgrader and the existing trunk pipeline facilities of Trans Mountain and Enbridge Pipelines Inc. in the Edmonton area. The completed pipeline system is estimated to cost $688 million.

The estimated cost is divided into two parts. $460 million is a target price, quoted to Shell and its partners by the Company. It contains fixed price bid amounts from third party contractors, a contingency amount and amounts estimated by Corridor, and is subject to certain agreed escalators. The balance of the cost, which includes line fill and interest costs, is comprised of amounts over which Corridor has no control or risk exposure, and which will be included in the rate base at cost.

The Corridor pipeline project has received all required regulatory approvals in addition to approvals from Shell and its partners. Construction on the project commenced in August 2000, and the project is proceeding on schedule and within budget. To December 31, 2001, $429.8 million has been spent on the project, including capital expenditures and deferred charges. Shell and its partners have made a long-term take or pay commitment to

transport a total of 155,000 barrels per day of bitumen and 65,000 barrels per day of diluent in the Corridor pipeline system. Initial start-up of the pipeline system is scheduled for the second quarter of 2002, and revenues under the firm service agreement with the shippers are expected to commence in early 2003.

Bison Pipeline

Bison Pipeline Limited, a wholly owned subsidiary of the Company, has proposed an $800 million, 516-km pipeline to transport bitumen from the Athabasca oil sands to the Edmonton area. Bison Pipeline is currently involved in joint engineering and technical studies with potential shippers, including TrueNorth Energy and Petro-Canada. Both potential shippers have filed or intend to file applications with the Alberta Energy Utilities Board (AEUB) to develop their respective bitumen production facilities.

Bison Pipeline is planning to file an AEUB application in the summer of 2002 and receive final regulatory approval in the first quarter of 2003. This regulatory schedule would allow Bison Pipeline to construct its system in time to meet the earliest shippers' planned production schedule of mid-2005. The project is subject to regulatory approvals and the execution of definitive transportation agreements with shippers.

Business Risks

Competitiveness

Trans Mountain's pipeline to the West Coast of North America is one of several alternatives for Western Canadian petroleum production. Throughput may decline in situations where West Coast prices are relatively lower than alternative prices in the U.S. Midwest.

Refined products can be imported for the British Columbia market through marine offloading facilities in the Port of Vancouver or by truck transportation from refineries in Washington State. In 2001, refined products for the British Columbia market represented approximately 31.9% of Trans Mountain's deliveries.

Revenues are affected by changes in throughput volumes. Under the incentive toll settlement for the Canadian mainline, this risk is mitigated by a mechanism that permits Trans Mountain to recover revenue shortfalls arising from average throughput below 28,500 m^3/day in subsequent years. However, recovery of any accumulated shortfall depends on sufficient throughput in subsequent years. Revenues associated with throughput on the U.S. pipeline are not covered by the incentive toll settlement, and are therefore directly affected by changes in U.S. throughput.

Expenses

Under the 2001-2005 incentive toll settlement, Trans Mountain is unable to incorporate most cost increases into its tolls and so bears greater risk associated with cost increases than in previous years. For example, ongoing deregulation of the electrical power industry in Alberta may result in significantly increased power costs. Trans Mountain is actively managing its power supply arrangements with the intention of mitigating the effect of power cost increases.

Negative Salvage Value

The cost of abandoning of the pipeline system at the eventual end of its useful life may not be fully recovered in tolls. Until such time as the magnitude of and the funding mechanism for the eventual recovery of negative salvage is determined, Trans Mountain, like other Canadian trunk pipeline systems, makes no provision for these amounts.

Operations

Trans Mountain has taken all reasonable and prudent steps to minimize its exposure in the case of a catastrophic event or environmental upset. Trans Mountain maintains a comprehensive Line Integrity Program as a preventive measure to mitigate

OTHER ACTIVITIES
Loss before Income Taxes
($ millions)

Earnings in 2001 were impacted by higher financing costs and weak economic conditions for BCG Services.

the risk of a pipeline failure or other loss of system integrity. The Program is intended to reduce both the likelihood and severity of the business interruption and/or environmental liability that could result from a loss of line integrity.

Sulphur Concentration

Volumes of refined products are subject to increases in sulphur concentration when transported in Trans Mountain's pipeline. The shippers of refined products have raised a concern that this may adversely affect their ability to meet pending regulations that will reduce the allowable sulphur concentrations in motor gasoline and diesel fuel sold in Canada. The regulations reducing the allowable sulphur content of gasoline and diesel fuel will take effect in 2005 and 2006, respectively. The Company is working with the refined product shippers to more fully understand the mechanisms leading to sulphur pick-up by refined products and apply those findings to implement measures to reduce or mitigate the increases in sulphur concentration.

OTHER ACTIVITIES

Contribution to Earnings

In millions of dollars	**2001**	2000
Revenues	**$102.9**	$ 87.7
Operating expenses		
Operation and maintenance	**29.2**	24.0
Depreciation and amortization	**3.0**	1.4
Property and other taxes	**0.3**	0.2
Cost of revenues	**71.4**	57.0
	103.9	82.6
Operating income (loss)	**(1.0)**	5.1
Financing costs	**8.7**	5.8
Loss before income taxes	**$ (9.7)**	$ (0.7)

Losses from other activities in 2001 were $9.7 million before income taxes compared with a loss of $0.7 million in 2000. This change was mainly the result of higher financing costs associated with new capital investments and weaker economic conditions for the Company's water services business, BCG Services Inc. (BCG Services). Although revenues and market share increased for BCG Services, economic conditions prevented an increase in gross margins that would have supported the increased operating costs that were incurred at BCG Services.

Revenues increased from $87.7 million in 2000 to $102.9 million in 2001 primarily as a result of higher sales volumes in BCG Services. Cost of revenues increased from $57.0 million in 2000 to $71.4 million in 2001 for the same reason. Operation and maintenance expenses increased $5.2 million to $29.2 million in 2001 as a result of integration costs in the water services business. Depreciation and amortization and property and other taxes increased in 2001 as a result of the acquisition of certain businesses. Financing costs increased by $2.9 million from 2000 to $8.7 million in 2001 as a result of increased debt outstanding to fund new capital investments.

Although revenues and market share increased for BCG Services in 2001, economic conditions prevented an increase in gross margins that would have supported the higher operating costs that were incurred at BCG Services to integrate the various water supply and services businesses that were acquired in 1999 and 2000. The Company anticipates that reduced operating costs, an improved economic climate, and a greater focus on water services will result in an improvement in the results from BCG Services in 2002.

ENRG

In June 2001, BCG eFuels Inc., a majority-owned subsidiary of the Company, and Pickens Fuel Corp. merged to create ENRG, the largest natural gas fuel provider for vehicles in North America. The new company provides vehicular natural gas – both

compressed natural gas (CNG) and liquefied natural gas (LNG) – and related services in key markets throughout North America. The initial combined customer base includes more than 25,000 fleet vehicles fuelling at more than 75 locations. The Company owns approximately 56% of ENRG.

CustomerWorks

On July 19, 2001, the Company and Enbridge Inc. announced the creation of a limited partnership, CustomerWorks, to develop and operate a new company that will provide full service customer management solutions to utilities, municipalities and retail energy companies across Canada. CustomerWorks is to be a leading provider of state-of-the-art utility customer management solutions and will support a complete set of business service offerings covering the entire meter-to-cash process including meter reading, billing, call centres, credit and collections, e-commerce, and field work appointment scheduling. The Company owns 30% of CustomerWorks.

Full-scale operations commenced January 1, 2002. CustomerWorks is initially providing services for more than 3.5 million customers of BC Gas Utility, Enbridge Consumers Gas, Enbridge Services Inc. and Enbridge Gas New Brunswick. These entities have contracted with CustomerWorks for services for terms of four or five years. BC Gas Utility's existing call centre and four existing Enbridge call centres became key operating sites, and a technology development centre is based in Vancouver. An estimated 775 Enbridge employees and 140 employees of the Company have been transferred to CustomerWorks. The transfer of certain BC Gas Utility assets is subject to regulatory approval, which is expected in March 2002.

Business Risks

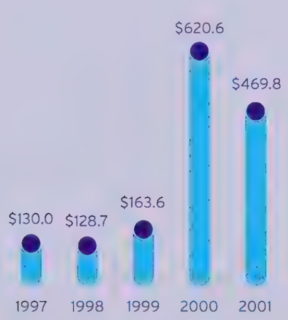
The other activities segment is relatively less significant than the Company's two other segments. Businesses in this segment primarily operate in unregulated industries which are, by their nature, more risky than BC Gas' regulated operations. Therefore, earnings contributions from these businesses are less predictable. Factors such as economic conditions, interest rates, foreign exchange rates and market pricing conditions may impact the results from these businesses.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from operating activities decreased to $59.8 million in 2001 from $179.3 million in 2000 as a result of a reduction in accounts payable, offset in part by higher net earnings after adjustments for non-cash items and reduced accounts receivable. The accounts payable balance at December 31, 2000 was unusually large as a result of payables for the Southern Crossing Pipeline project and natural gas purchased during December 2000 at high market prices.

Capital expenditures totaled $469.8 million in 2001 compared with $620.6 million in 2000. The $150.8 million decrease in capital spending was due mainly to expenditures in 2000 on the Southern Crossing Pipeline project, offset in part by higher expenditures in 2001 on the Corridor Pipeline.

BC GAS INC.
Consolidated Capital Expenditures
($ millions)



Capital expenditures in 2000 reflected investments in both the Southern Crossing and Corridor Pipelines.

The capital spending in 2001 is summarized as follows:

2001 Capital Expenditures
In millions of dollars

Natural gas distribution	
Mains, services and engineering projects	**$ 57.6**
Land and buildings	**3.3**
Systems and computer hardware	**25.8**
Southern Crossing Pipeline	**31.3**
Capitalized overhead	**23.9**
Other	**4.1**
	146.0
Petroleum transportation	
Trans Mountain	**16.5**
Corridor Pipeline	**291.1**
	307.6
Other activities	**16.2**
Total	**$469.8**

Coverage Ratios

Due to the capital intensive nature of the Company's businesses and the need to raise debt frequently in the fixed income market, maintenance of its financial ratios is a priority for BC Gas. The most significant ratios are considered to be interest coverage and total debt to shareholders' equity. These are presented below on a consolidated basis for BC Gas Inc., BC Gas Utility and Trans Mountain. Coverage ratios for Corridor are not meaningful while the pipeline is under construction.

Financial Ratios	2001	2000
Interest coverage		
BC Gas Inc.	**2.0**	2.2
BC Gas Utility	**1.9**	2.1
Trans Mountain	**4.8**	3.7
Debt to shareholders' equity		
BC Gas Inc.	**2.9:1**	2.5:1
BC Gas Utility	**2.2:1**	2.1:1
Trans Mountain	**1.0:1**	1.1:1

Interest coverage for BC Gas and BC Gas Utility declined in 2001 compared to 2000 as a result of lower corporate income tax rates and the refinancing of $75 million of BC Gas Utility preferred shares with debt in October 2000. Lower income taxes reduce interest coverage ratios for regulated utilities as the tax savings are passed through to customers in lower rates, which reduces earnings before interest and taxes. Debt to shareholders' equity for BC Gas increased in 2001 compared to 2000 as a result of borrowings associated with the Corridor Pipeline project.

Credit Ratings

Securities issued by BC Gas, BC Gas Utility, Trans Mountain and Corridor are rated by three credit rating agencies: DBRS Inc. (DBRS), Moody's Investors Service Inc. (Moody's) and Standard & Poor's, a division of The McGraw-Hill Companies (S&P). The ratings assigned to securities issued by the BC Gas group of companies are reviewed by these agencies on an ongoing basis.

The table below summarizes the ratings assigned to the Company's various securities at December 31, 2001.

Credit Ratings	DBRS	Moody's	S&P
BC Gas Inc.			
Commercial paper	R-1 (Low)		A-1 (Low)
Medium term note debentures	A (Low)	A3	BBB
Capital securities	BBB (High)	Baa1	BBB-
BC Gas Utility			
Commercial paper	R-1 (Low)		A-1 (Low)
Unsecured debentures	A	A2	BBB+
Medium term note debentures	A	A2	BBB+
Purchase money mortgages	A	A1	A-
Trans Mountain			
Commercial paper	R-1 (Low)		A-1 (Low)
Unsecured debentures	A (Low)		BBB+
Corridor			
Commercial paper	R-1 (Low)		A-1 (Low)

Projected Capital Expenditures

BC Gas has estimated total 2002 consolidated capital expenditures of $428.8 million, excluding any capital expenditures by Centra Gas B.C.

Expenditures on the Corridor Pipeline are being financed by commercial paper borrowings, which are supported by a credit facility from a syndicate of banks. The Company expects to finance other capital expenditures with a combination of long-term debt and hybrid equity issuance, short-term borrowings and internally generated funds. The breakdown of projected capital expenditures for 2002 is as follows:

Projected 2002 Capital Expenditures
In millions of dollars

Natural gas distribution	
Mains, services and engineering projects	$ 77.6
Land and buildings	2.1
Systems and computer hardware	23.5
Capitalized overhead	23.9
Other	2.3
	129.4
Petroleum transportation	
Trans Mountain	21.7
Corridor Pipeline	246.5
	268.2
Other activities	31.2
Total	$428.8

Rate Stabilization Accounts

As discussed under Regulation and Rates – BC Gas Utility, the rate stabilization accounts permit the Utility to recover the difference between projected and actual gas costs in future rates. However, increasing balances receivable from customers in the rate stabilization accounts create a financing requirement until the balances are recovered in customer rates. The Company expects to finance any further increases in rate stabilization account balances through debt issuance by BC Gas Utility.

Public Issues

During the year, BC Gas Utility issued $100 million of medium term note debentures at an interest rate of 6.15%. This compares with $425 million issued in 2000 at an average interest rate of 6.35%. In addition, BC Gas issued $200 million of medium term note debentures at an interest rate of 6.30%.

On November 20, 2001, BC Gas issued 5,208,000 Subscription Receipts for gross proceeds of $188.3 million. The net proceeds of the offering will be used to partially fund the acquisition of Centra Gas. Upon the closing of the acquisition, each Subscription Receipt will be automatically converted into one BC Gas common share and any dividends paid to BC Gas common shareholders prior to conversion will be payable to Subscription Receipt holders. In the event that the acquisition does not close before March 28, 2002, BC Gas will repay the Subscription Receipts in full with applicable interest.

Lines of Credit

At December 31, 2001, the Company had lines of credit in place totaling $1,525 million to finance cash requirements, comprising $200 million at BC Gas, $500 million at BC Gas Utility, $125 million at Trans Mountain and $700 million at Corridor. These lines enable the respective companies to borrow directly from their bankers, issue bankers' acceptances and support commercial paper issued by each company. Bank lines of $816 million were unutilized at the end of 2001. Virtually all short-term cash needs are funded through commercial paper and bankers' acceptances in the Canadian market at rates generally below bank prime.

Dividends

The dividends paid on BC Gas' common shares in 2001 were $1.30 per share, up from $1.225 per share in 2000. In aggregate, BC Gas paid common shareholder dividends of $49.8 million in 2001 compared to $46.9 million in 2000, reflecting the increased dividend per share.

BC GAS INC.
Dividends Paid
per Share
(dollars)

Since 1997, dividends per share have grown by 33%.

Financial Instruments and Risk Management

The Company uses financial instruments from time to time to manage its exposure to changes in interest rates where the interest rate risk is not managed through the use of interest rate deferral accounts. These financial instruments are used only for hedging purposes, and are employed only in connection with an underlying asset or liability through counterparties with acceptable credit status.

BC Gas, through its natural gas distribution operations, has undertaken a natural gas price risk management program on behalf of its customers to manage the price volatility of its forecast system gas supply. Part of this program involves the use of financial instruments to effectively fix the price of baseload gas supply.

OTHER MATTERS

Union Settlements

New collective agreements with BC Gas Utility employees represented by the Office and Professional Employees International Union (Local 378) and the International Brotherhood of Electrical Workers (Local 213) were agreed to during the third quarter of 2001. The new agreements expire on March 31, 2002 and March 31, 2006, respectively.

OUTLOOK

BC Gas is continuing to execute its focused strategy of delivering attractive growth through investments in low risk businesses. Through projects such as the Corridor Pipeline, the Bison Pipeline, and the Inland Pacific Connector Pipeline, and through initiatives such as the acquisition of Centra Gas, BC Gas is positioned to meet the growing needs for natural gas and petroleum transportation in Western Canada.

Although market prices for natural gas have declined from the record highs experienced in the winter of 2000/2001, BC Gas continues to believe in the need for initiatives that will prevent future price spikes when the North American economy and demand for energy recovers. BC Gas is actively pursuing initiatives such as demand-side management, price risk management, and new infrastructure projects such as the Inland Pacific Connector to ensure the long-term competitiveness of natural gas in BC Gas' service area.

The acquisition of Centra Gas will present opportunities and challenges for the Company, both from an operating and regulatory perspective. The development of a new incentive regulatory settlement in 2002 for BC Gas Utility and Centra Gas is essential to ensuring that the Company has the opportunity to create value for both customers and shareholders of BC Gas.

Trans Mountain's performance under its new Incentive Toll Settlement demonstrates the opportunities that are available for both customers and shareholders with a balanced approach to incentive regulation. The Company is also capitalizing on its experience with the Corridor Pipeline to meet the needs of new shippers in the Alberta oil sands, through the proposed Bison Pipeline.

BC Gas' multi-utility businesses complement the growth in natural gas distribution and petroleum transportation by positioning the Company to capture longer-term growth opportunities in natural gas, water and electricity distribution. CustomerWorks has the economies of scale to competitively offer customer care services in a multi-utility environment. BCG Services is pursuing opportunities in the operation of water distribution assets.

BC Gas is committed to delivering on its financial targets while maintaining a low risk profile and focusing on the Company's core businesses. The Company is confident that it can achieve these objectives in the long term through efficient operations, infrastructure development and developing its multi-utility activities.

MANAGEMENT'S RESPONSIBILITY

The consolidated financial statements have been prepared by management, which is responsible for the integrity and objectivity of this information. These financial statements have been prepared in conformity with Canadian generally accepted accounting principles and, where appropriate, include some amounts that are based on management's best estimates and judgments. The financial information presented elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management has established systems of internal control which are designed to provide reasonable assurance that assets are safeguarded from loss and that reliable financial records are maintained. These systems are monitored by internal auditors.

KPMG LLP, the auditors appointed by the shareholders, have reviewed the systems of internal control and examined the consolidated financial statements in accordance with Canadian generally accepted auditing standards to enable them to express an independent opinion on the consolidated financial statements. Their report is set out below.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting and internal control. The Audit Committee meets with the internal auditors, the independent auditors and management to discuss auditing and financial matters and to review the consolidated financial statements and the independent auditors' report. The Audit Committee reports its findings to the Board for consideration in approving the consolidated financial statements for issuance to the shareholders.

J.M. Reid

John M. Reid
President and Chief Executive Officer

M.C. Woensdregt

Milton C. Woensdregt
Senior Vice President, Finance,
Chief Financial Officer and Treasurer

Vancouver, Canada
February 1, 2002

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated statements of financial position of BC Gas Inc. as at December 31, 2001 and 2000 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles. As required by the *Company Act (British Columbia)*, we report that, in our opinion, these principles have been applied on a consistent basis.

KPMG LLP

Chartered Accountants
Vancouver, Canada
February 1, 2002

CONSOLIDATED STATEMENTS OF EARNINGS

(In millions of dollars, except per share amounts)

Years ended December 31	**2001**	2000
REVENUES		
Natural gas distribution	**$1,420.3**	$1,085.4
Petroleum transportation	**143.1**	132.5
Other activities	**102.9**	87.7
	1,666.3	1,305.6
EXPENSES		
Cost of natural gas	**931.8**	658.4
Operation and maintenance	**212.0**	195.4
Depreciation and amortization	**95.1**	86.2
Property and other taxes	**60.8**	52.0
Cost of revenues from other activities	**71.4**	57.0
	1,371.1	1,049.0
OPERATING INCOME	**295.2**	256.6
Financing costs (note 8)	**148.3**	117.5
Restructuring costs (note 10)	**–**	13.5
Earnings before income taxes and non-controlling interest	**146.9**	125.6
Income taxes on earnings (note 9)	**55.9**	37.9
Income tax benefits from NW Energy (note 10)	**–**	(29.0)
	55.9	8.9
Earnings before non-controlling interest	**91.0**	116.7
Non-controlling interest (note 10)	**–**	4.0
NET EARNINGS	**91.0**	112.7
Capital securities distributions, net of income taxes (note 4)	**6.4**	3.9
EARNINGS APPLICABLE TO COMMON SHARES	**$ 84.6**	$ 108.8
Common shares – weighted average (millions)	**38.3**	38.3
BASIC EARNINGS PER COMMON SHARE (note 11)	**$ 2.21**	$ 2.84
DILUTED EARNINGS PER COMMON SHARE (note 11)	**$ 2.19**	$ 2.82

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(In millions of dollars)

Years ended December 31	**2001**	2000
Retained earnings, beginning of year	**$ 240.7**	$ 183.2
Net earnings	**91.0**	112.7
	331.7	295.9
Dividends on common shares	**49.8**	46.9
Capital securities distributions, net of income taxes	**6.4**	3.9
Share options purchased (note 5)	**4.5**	1.7
Capital securities issue costs, net of income taxes	**–**	2.7
	60.7	55.2
Retained earnings, end of year	**$ 271.0**	$ 240.7

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(In millions of dollars)

December 31	**2001**	2000
ASSETS		
Current assets		
Cash	**$ 2.1**	$ 22.4
Accounts receivable	**270.6**	460.4
Inventories of gas in storage and supplies	**116.5**	96.6
Prepaid expenses	**8.4**	6.8
Current portion of rate stabilization accounts	**105.9**	45.0
	503.5	631.2
Property, plant and equipment (note 1)	**3,079.9**	2,727.6
Rate stabilization accounts	**41.8**	105.1
Other assets (note 2)	**80.5**	49.2
	$ 3,705.7	$ 3,513.1
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term notes	**$ 305.0**	$ 387.0
Accounts payable and accrued liabilities	**310.4**	625.7
Income and other taxes payable	**18.7**	9.2
Current portion of long-term debt (note 3)	**223.6**	72.5
	857.7	1,094.4
Long-term debt (note 3)	**1,928.0**	1,561.9
Deferred gain (note 14)	**23.1**	–
Future income taxes	**56.8**	47.3
	2,865.6	2,703.6
Shareholders' equity		
Capital securities (note 4)	**125.0**	125.0
Common shares (note 4)	**364.3**	364.0
Contributed surplus	**130.8**	130.8
Retained earnings	**271.0**	240.7
	891.1	860.5
Less cost of common shares held by Trans Mountain	**51.0**	51.0
	840.1	809.5
	$ 3,705.7	$ 3,513.1

Approved by the Board:

Ronald L. Cliff
Director

John M. Reid
Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions of dollars)

Years ended December 31	2001	2000
Cash flows provided by (used for)		
Operating activities		
Net earnings	**$ 91.0**	$ 112.7
Adjustments for non-cash items		
Depreciation and amortization	**95.1**	86.2
Future income taxes	**9.5**	(18.1)
Other	**(0.7)**	(4.4)
	194.9	176.4
Decrease (increase) in rate stabilization accounts	**2.4**	(117.3)
Changes in non-cash operating working capital	**(137.5)**	120.2
	59.8	179.3
Investing activities		
Property, plant and equipment	**(469.8)**	(620.6)
Proceeds on sale of natural gas pipeline assets (note 14)	**47.5**	–
Other assets	**(32.6)**	(27.8)
	(454.9)	(648.4)
Financing activities		
Decrease in short-term notes	**(82.0)**	(65.0)
Increase in long-term debt	**590.8**	558.6
Reduction of long-term debt	**(73.6)**	(3.2)
Reduction of non-controlling interest (note 10)	**–**	(75.0)
Issue of capital securities, net of issue costs	**–**	122.3
Issue of common shares and share options purchased	**(4.2)**	(1.0)
Dividends and distributions on common shares and capital securities	**(56.2)**	(50.8)
	374.8	485.9
Net increase (decrease) in cash	**(20.3)**	16.8
Cash at beginning of year	**22.4**	5.6
Cash at end of year	**$ 2.1**	$ 22.4
Supplemental disclosure of cash flow information		
Amount of interest paid in the year	**$ 159.0**	$ 114.6
Amount of income taxes paid (recovered) in the year	**7.7**	(4.4)

Cash is defined as cash or bank indebtedness

SIGNIFICANT ACCOUNTING POLICIES

The preparation of these consolidated financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts in the financial statements and the disclosure of contingent assets and liabilities. A significant area requiring the use of management estimates relates to the determination of useful lives for depreciation and amortization. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below:

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its subsidiaries. The natural gas distribution operations are conducted through BC Gas Utility Ltd. ("the Utility"). The petroleum transportation operations are carried out through Trans Mountain Pipe Line Company Ltd. ("Trans Mountain") which owns and operates a common carrier pipeline system for crude and refined petroleum products and through Corridor Pipeline Limited ("Corridor") which is currently constructing a pipeline in Northern Alberta to transport diluted bitumen.

As at December 31, 2001, Trans Mountain owned 10.7% (2000 – 10.7%) of the common shares of the Company. The cost of these shares is shown as a deduction from shareholders' equity.

REGULATION

The Utility is subject to the regulation of the British Columbia Utilities Commission ("the Commission"). Trans Mountain's operations are regulated in Canada by the National Energy Board and, in the United States, tariff matters are regulated by the Federal Energy Regulatory Commission.

These regulatory authorities exercise statutory authority over such matters as rate of return, construction and operation of facilities, accounting practices, and rates and tolls. With respect to Corridor, these matters are governed by contractual arrangements with shippers and are subject to regulation by the Alberta Energy and Utilities Board.

INVENTORIES

Inventories of gas in storage and supplies are valued at cost determined mainly on a moving-average basis. Other inventories are valued at the lower of cost and net realizable value.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost which includes all direct costs, betterments, an allocation of overhead costs and an allowance for funds used during construction.

Depreciation of regulated assets is provided on a straight-line basis on plant in service at rates approved by regulatory authorities. The cost of depreciable property retired, together with removal costs less salvage, is charged to accumulated depreciation.

Depreciation of non-regulated equipment is provided using the declining balance method.

No provision for future removal and site restoration obligations has been accrued for regulated operations as the extent of such costs is not currently determinable. Management expects that such costs would be recoverable through future rates or tolls.

RATE STABILIZATION ACCOUNTS

The Utility is authorized by the Commission to maintain two rate stabilization accounts to mitigate the effect on its earnings of unpredictable and uncontrollable factors, principally temperature and cost of natural gas fluctuations.

The gas cost reconciliation account ("GCRA") accumulates unforecasted changes in natural gas costs and natural gas cost recoveries. The revenue stabilization adjustment mechanism ("RSAM") accumulates the margin impact of variations in the actual use for residential and commercial customers from forecast use. The balances are amortized as approved by the Commission.

DEFERRED CHARGES

The Company defers certain charges which the regulatory authorities or contractual arrangements require or permit to be recovered through future rates or tolls. Deferred charges are amortized over various periods depending on the nature of the charges and include financing costs, such as long-term debt issue costs, which are amortized over the original lives of the related debt.

Deferred charges not subject to regulation relate to projects which may benefit future periods and will be capitalized on completion or expensed on abandonment of the projects. Amortization is provided on a straight-line basis over periods from five to ten years.

GOODWILL AND INTANGIBLE ASSETS

Goodwill and intangible assets represent the excess of the purchase price over the fair value of the net assets acquired. Goodwill and intangible assets are being amortized over 20 years. Management reviews on an ongoing basis the valuation and amortization of goodwill and intangible assets taking into consideration any events and circumstances which might have impaired the net book value. Goodwill and intangible assets are written down when declines in value are considered to be other than temporary based upon expected undiscounted cash flows of the entity to which the goodwill and intangible assets relate.

REVENUES

Revenues are recorded when products have been delivered or services have been performed.

The natural gas distribution utilities record revenues from natural gas sales on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the reporting period and adjusted for the RSAM and other approved Commission orders.

For the petroleum transportation operations, revenues are recorded when products are delivered and adjusted according to terms prescribed by the Incentive Toll Settlements with the shippers approved by the National Energy Board.

EMPLOYEE BENEFIT PLANS

The Company accrues its obligations under employee benefit plans and the related costs, net of plan assets, as the underlying services are provided. The cost of pensions and other retirement benefits earned by employees is actuarially determined using the projected benefit method prorated on services and reflects management's best estimates of expected plan investment performance, salary growth, future terminations, expected health care costs, mortality rates and retirement ages of plan members. For the purpose of calculating the expected return on plan assets, those assets are valued at fair value. Adjustments that result from plan amendments, changes in assumptions and experience gains and losses are amortized over the expected average remaining service life of the employee group covered by the plan. A current settlement discount rate is used to measure the accrued pension benefit obligation instead of using a long-term rate of return.

The costs of providing pension and post employment benefits match the recovery of these costs in rates.

INCOME TAXES

The Company's regulated subsidiaries account for income taxes for regulated operations as prescribed by their respective regulatory authorities. This includes following the taxes payable method of accounting for income taxes and accounting for certain assets and the rate stabilization accounts on a net of realized tax savings basis as approved by the Commission. This method is followed as there is reasonable expectation that all taxes payable in future years will be recoverable from customers at that time.

The Company and its other non-regulated subsidiaries follow the asset and liability method of accounting for future income taxes. Under this method, future income taxes are determined based on differences between the accounting and tax basis of assets and liabilities.

SHARE BASED COMPENSATION

The Company has a common share option plan which is described in note 5. No compensation expense is recognized for the share option plan when the options are issued. Any consideration paid by employees on the exercise of the share option is credited to common shares while consideration paid to re-purchase share options from participants is charged to retained earnings, net of the related income taxes.

EARNINGS PER SHARE

Effective January 1, 2001, the Company adopted the new recommendations of the Canadian Institute of Chartered Accountants ("CICA") relating to Section 3500 ("Earnings Per Share") of the CICA Handbook. This new standard is mandatory for fiscal years beginning on or after January 1, 2001, and has been given retroactive application. Under this new standard, the treasury stock method is used instead of the imputed earnings approach for determining the dilutive effect of options issued in presenting diluted earnings per share. The new standard has no effect on the computation of basic earnings per share reported by the Company.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Tabular amounts in millions of dollars, except per share amounts)
Years ended December 31, 2001 and 2000

1. PROPERTY, PLANT AND EQUIPMENT

2001

	Depreciation rates	Cost	Accumulated depreciation	Net book value
Natural gas and petroleum pipeline systems	**1% – 10%**	**$ 2,935.3**	**$ 628.2**	**$ 2,307.1**
Pipeline under construction	**0%**	**418.7**	**–**	**418.7**
Plant, buildings and equipment	**1% – 33%**	**358.9**	**122.6**	**236.3**
Land and land rights	**0% – 5%**	**118.9**	**1.1**	**117.8**
		$ 3,831.8	**$ 751.9**	**$ 3,079.9**

2000

	Depreciation rates	Cost	Accumulated depreciation	Net book value
Natural gas and petroleum pipeline systems	1% – 10%	$ 2,859.1	$ 585.9	$ 2,273.2
Pipeline under construction	0%	127.6	–	127.6
Plant, buildings and equipment	1% – 33%	324.7	112.5	212.2
Land and land rights	0% – 5%	115.8	1.2	114.6
		$ 3,427.2	$ 699.6	$ 2,727.6

The composite depreciation rate on regulated property, plant and equipment for the year ended December 31, 2001 is approximately 2.9% (2000 – 3.0%).

2. OTHER ASSETS

	2001	2000
Deferred charges		
Subject to regulation	**$ 25.8**	$ 26.3
Not subject to regulation	**12.5**	3.2
	38.3	29.5
Investments	**9.1**	8.9
Goodwill and intangible assets	**21.8**	8.7
Long-term receivables	**11.3**	2.1
	$ 80.5	$ 49.2

3. LONG-TERM DEBT

	2001	2000
BC Gas Inc.		
(a) 6.30% Series 1 Medium Term Note Debentures, due December 1, 2008	$ 200.0	$ –
BC Gas Utility Ltd.		
(b) Purchase Money Mortgages:		
11.80% Series A, due September 30, 2015	74.9	74.9
10.30% Series B, due September 30, 2016	200.0	200.0
(c) Debentures:		
9.75% Series D, due December 17, 2006	20.0	20.0
10.75% Series E, due June 8, 2009	59.9	59.9
8.50% Series F, due August 26, 2002	100.0	100.0
8.15% Series H, due July 28, 2003	50.0	50.0
(d) Medium Term Note Debentures:		
6.20% Series 9, due June 2, 2008	188.0	188.0
5.10% Series 10, due February 2, 2001	–	50.0
6.95% Series 11, due September 21, 2029	150.0	150.0
6.50% Series 12, due July 20, 2005	200.0	200.0
6.50% Series 13, due October 16, 2007	100.0	100.0
6.00% Series 14, due October 23, 2003	50.0	50.0
6.00% Series 15, due December 11, 2002	75.0	75.0
6.15% Series 16, due July 31, 2006	100.0	–
Various series, weighted average interest rate of 9.63% (2000 – 8.74%) due in 2005	45.0	65.0
Obligations under capital leases, at 5.93% (2000 – 6.00%)	14.0	13.7
	1,426.8	1,396.5
Trans Mountain Pipe Line Company Ltd.		
(e) Debentures:		
9.75% Series A, due February 18, 2002	44.9	44.9
10.75% Series B, due November 22, 2004	30.0	30.0
11.50% Series C, due June 20, 2010	35.0	35.0
	109.9	109.9
Corridor Pipeline Limited		
(f) Commercial Paper at short-term floating rates, weighted average interest rate of 2.69% (2000 – 5.75%)	404.0	128.0
Other long-term debt	10.9	–
Total long-term debt	2,151.6	1,634.4
Less current portion of long-term debt	223.6	72.5
	$ 1,928.0	$ 1,561.9

(a) BC Gas Inc. Medium Term Note Debentures:
The Company's Medium Term Note Debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 21, 2001.

(b) BC Gas Utility Purchase Money Mortgages:
The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on the Utility's Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to $425 million.

During 2000, holders of $74.9 million of the 11.80% Series A Purchase Money Mortgages originally due on September 30, 2000 exercised their option to extend them to September 30, 2015 at a rate of 11.80%.

(c) BC Gas Utility Debentures:
The BC Gas Utility debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

(d) BC Gas Utility Medium Term Note Debentures:
The Utility's Medium Term Note Debentures are unsecured obligations but are subject to the terms of the Trust Indenture dated November 1, 1977 (see note 3(c)).

(e) Trans Mountain Debentures:
The Trans Mountain debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated February 18, 1987, as amended and supplemented.

(f) Corridor Commercial Paper:
The commercial paper program to finance the Corridor pipeline is supported by a syndicated bank credit facility that is committed during the construction period and for three years following the commencement of payments under the transportation contract. The indebtedness under this credit facility and the commercial paper program are guaranteed by the Company.

The Company's Series 1 Medium Term Note Debentures, the Utility's Series B Purchase Money Mortgages, Series E, Series F and Series H Debentures, and Series 11, Series 13 and Series 16 Medium Term Note Debentures, and Trans Mountain's Series B and Series C Debentures are redeemable in whole or in part at the option of the Company at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond.

Required principal repayments over the next five years are as follows:

2002	$ 223.6
2003	104.5
2004	33.1
2005	248.0
2006	532.5

4. CAPITAL SECURITIES AND COMMON SHARES

Authorized Share Capital
The Company is authorized to issue 750,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value.

Capital Securities
On April 19, 2000, the Company issued $125.0 million of 8.0% Capital Securities with a term to maturity of 40 years for gross proceeds of $123.7 million. The Company may elect to defer payments on these securities and settle such deferred payments in either cash or common shares, and has the option to settle principal at maturity through the issuance of common shares. Accordingly, the capital securities have been classified as equity. The securities are exchangeable at the option of the holder on or after April 19, 2010 for common shares of the Company at 90% of the market price, subject to the right of the Company to redeem the securities for cash. Distributions on these securities, net of related income taxes, are deducted from net earnings for the purpose of calculating earnings applicable to common shares.

Common Shares

Changes in the issued and outstanding common shares are as follows:

	2001		2000	
	Number	Amount	Number	Amount
Outstanding, beginning of year	**42,918,876**	**$ 364.0**	42,871,705	$ 363.3
Issued under:				
Share option plan	**17,183**	**0.3**	43,803	0.6
Payroll deduction employee share purchase plan	**–**	**–**	3,368	0.1
	42,936,059	**$ 364.3**	42,918,876	$ 364.0
Less common shares held by Trans Mountain	**4,592,094**		4,592,094	
Outstanding, end of year	**38,343,965**		38,326,782	

Reserved for Issue

At December 31, 2001 the number of common shares reserved for issue to meet rights outstanding is as follows:

Under share option plan	3,675,467
Under dividend reinvestment and share purchase plan	2,062,576
Under payroll deduction employee share purchase plan	414,512
	6,152,555

5. SHARE OPTION PLAN

The Company has a Share Option Plan whereby officers, directors and certain employees may be granted options to purchase a maximum of 6,300,000 unissued common shares with terms up to ten years. The option exercise price is the closing sale price of the common shares on the Toronto Stock Exchange on the trading day prior to the date the option is granted. The Plan provides an optionee with the right, by notice in writing, to request the Company to purchase from the optionee for cash all or part of the vested options as specified in the notice at a price equal to the difference between the market price on the day the notice is received by the Company and the exercise price for those options. Upon receipt of notice requesting the Company to purchase the options from the optionee, the Company has the right to override the request and require the optionee to determine whether or not to exercise the option for unissued common shares. Options purchased by the Company are cancelled.

There are two categories of options which have been issued under the Share Option Plan, Regular Share Options and Performance Based Share Options.

Regular Share Options

Since 2000, the Company granted options with eight-year terms which are exercisable on a cumulative basis and vest at one-third per annum on the anniversary of the option grant date. Prior to 2000, the Company granted options with ten-year terms which are exercisable on a cumulative basis at 20% per annum.

Changes in outstanding regular share options during 2001 and 2000 and outstanding options for common shares at December 31, 2001 and 2000 are as follows:

	2001		2000	
	Shares	Weighted average exercise price	Shares	Weighted average exercise price
Outstanding, beginning of year	**938,175**	**$ 21.40**	971,045	$ 18.67
Granted during the year	**42,400**	**31.00**	244,250	25.37
Exercised	**(17,183)**	**15.91**	(43,803)	14.95
Forfeited and expired	**(9,671)**	**26.67**	(17,987)	19.69
Repurchased	**(342,872)**	**17.58**	(215,330)	15.11
Outstanding, end of year	**610,849**	**$ 24.28**	938,175	$ 21.40
Exercisable, end of year	**402,303**	**$ 22.41**	617,475	$ 18.59

	Options outstanding			Options exercisable	
Exercise price range	Number of common shares	Weighted-average exercise price	Weighted-average remaining contractual life	Number exercisable at year-end	Weighted-average exercise price
\$13.87 – \$18.00	140,218	\$ 14.80	2.5	140,218	\$ 14.80
\$21.20 – \$26.65	274,591	25.60	5.9	161,260	25.03
\$27.50 – \$31.85	196,040	29.22	6.5	100,825	28.80
	610,849	\$ 24.28	5.3	402,303	\$ 22.41

Performance Based Share Options

The Company has issued performance based share options with eight-year terms. The options vest at one-third per annum on the anniversary of the option grant dates, subject to the market price of the Company's common shares reaching 125% of the option's exercise price for at least 10 out of 15 consecutive trading days within four years of the option grant date. If the market price requirement is not attained in the first four years, the optionee is still eligible to exercise two-thirds of the granted options if the common share price reaches 125% of the option's exercise price for at least 10 out of 15 consecutive trading days during the subsequent four years.

Changes in outstanding performance based share options during 2001 and 2000 and outstanding options for common shares at December 31, 2001 and 2000 are as follows:

	2001		2000	
	Shares	Weighted average exercise price	Shares	Weighted average exercise price
Outstanding, beginning of year	**491,577**	**\$ 25.39**	295,650	\$ 26.94
Granted during the year	**282,300**	**31.30**	207,327	23.17
Forfeited and expired	**(56,118)**	**27.86**	(11,400)	25.00
Repurchased	**(40,484)**	**25.35**	–	–
Outstanding, end of year	**677,275**	**\$ 27.66**	491,577	\$ 25.39
Exercisable, end of year	**211,175**	**\$ 26.13**	–	\$ –

	Options outstanding			Options exercisable	
Exercise price range	Number of common shares	Weighted-average exercise price	Weighted-average remaining contractual life	Number exercisable at year-end	Weighted-average exercise price
\$22.50 – \$27.25	423,925	\$25.45	5.7	211,175	\$26.13
\$31.00 – \$35.00	253,350	31.34	7.2	–	–
	677,275	\$27.66	6.3	211,175	\$26.13

During 2001, options to purchase 383,356 (2000 – 215,330) common shares were purchased for \$4.5 million (2000 – \$1.7 million), net of income tax benefits, which has been charged to retained earnings.

6. AGREEMENT TO ACQUIRE CENTRA GAS AND SUBSCRIPTION RECEIPT FINANCING

On October 22, 2001 the Company entered into an agreement to acquire all of the outstanding shares and intercorporate debt of Centra Gas British Columbia Inc. and Centra Gas Whistler Inc. from Westcoast Energy Inc. (the "Acquisition"). The Acquisition will be satisfied by a payment of $310 million cash (subject to adjustments) at closing, and a $52 million deferred payment, payable on December 31, 2011 or sooner if Centra realizes revenues from transportation contracts with power generating plants which may be constructed in Centra's service area. The purchase is subject to governmental approval, and is expected to be finalized in early March 2002.

On November 20, 2001 the Company issued 5,208,000 subscription receipts at a price of $36.15 per subscription receipt for gross proceeds of $188.3 million. Proceeds from the sale are held in escrow by a trustee and accordingly are not recorded in the consolidated statement of financial position. Upon the closing of the Acquisition, each subscription receipt will be automatically converted into one common share of the Company and any dividends paid to common shareholders prior to conversion will be paid to subscription receipt holders. In the event that the Acquisition does not close before March 28, 2002, the subscription receipts will be repaid in full with applicable interest.

7. EMPLOYEE BENEFIT PLANS

The Company has defined benefit plans and a defined contribution plan for employees. The Company also provides post employment benefits other than pensions including supplemental health, dental and life insurance coverage for retired employees. Information about these benefit plans is as follows:

	Pension benefit plans		Other benefit plans	
	2001	2000	**2001**	2000
Plan assets				
Fair value at beginning of year	**$ 225.3**	$ 204.4	**$ –**	$ –
Return on plan assets	**1.8**	18.9	**–**	–
Company contributions	**3.5**	3.5	**–**	–
Members' contributions	**3.1**	2.9	**–**	–
Benefits and settlements paid	**(10.0)**	(14.7)	**–**	–
Change in accounting method	**–**	10.3	**–**	–
Fair value at end of year	**223.7**	225.3	**–**	–
Accrued benefit obligation				
Balance at beginning of year	**194.4**	187.8	**30.9**	26.7
Current service cost	**6.3**	5.9	**0.9**	0.9
Interest cost	**14.0**	12.5	**2.2**	2.0
Members' contributions	**3.1**	2.9	**–**	–
Benefits and settlements paid	**(10.0)**	(13.6)	**(0.8)**	(0.7)
Change in accounting method	**–**	(7.2)	**–**	–
Change in discount rate	**11.6**	6.8	**2.9**	2.4
Other	**2.1**	(0.7)	**–**	(0.4)
Balance at end of year	**221.5**	194.4	**36.1**	30.9
Plan surplus (deficiency)	**2.2**	30.9	**(36.1)**	(30.9)
Unamortized transitional obligation (benefit)	**(37.4)**	(40.7)	**19.8**	22.4
Unamortized actuarial loss	**30.0**	3.7	**5.3**	2.4
Unamortized past service costs	**2.6**	0.9	**–**	–
Accrued benefit liability	**$ (2.6)**	$ (5.2)	**$ (11.0)**	$ (6.1)

Included in the above pension benefit plans is a liability of $13.6 million at December 31, 2001 (2000 – $15.9 million) regarding defined benefit plans which have not been funded. These unfunded pension obligations are secured by a letter of credit.

Significant Assumptions

The significant actuarial assumptions adopted in measuring the Company's accrued benefit obligations are as follows (weighted-average assumptions as of December 31):

	Pension benefit plans		Other benefit plans	
	2001	2000	**2001**	2000
Discount rate	**6.81%**	7.19%	**6.50%**	7.00%
Expected rate of return on plan assets	**7.15%**	7.16%	**–**	–
Rate of compensation increase	**3.21%**	3.29%	**–**	–

For measurement purposes, an 11% health care cost trend rate was assumed for 2000, decreasing gradually to 5% in 2006 and remaining at that level thereafter.

Net Benefit Plan Expense

	Pension benefit plans		Other benefit plans	
	2001	2000	**2001**	2000
Current service cost	**$ 6.3**	$ 5.9	**$ 0.9**	$ 0.9
Interest cost	**14.0**	12.5	**2.2**	2.0
Expected return on plan assets	**(15.7)**	(14.7)	**–**	–
Amortization of transitional obligation (benefit) and other changes	**(3.4)**	(3.4)	**2.6**	2.8
Other	**0.2**	(0.3)	**–**	(0.5)
Net benefit plan expense	**$ 1.4**	$ –	**$ 5.7**	$ 5.2

The Company's defined contribution plan was introduced on January 1, 2000 and the expense for 2001 was $1.1 million (2000 – $1.0 million).

8. FINANCING COSTS

	2001	2000
Interest and expense on long-term debt	**$ 128.9**	$ 106.5
Other interest	**34.8**	19.5
Interest capitalized	**(15.4)**	(8.5)
	$ 148.3	$ 117.5

9. INCOME TAXES

Income Taxes on Earnings

	2001	2000
Current	**$ 46.4**	$ 54.9
Future	**9.5**	(17.0)
	$ 55.9	$ 37.9

Variation in Effective Income Tax Rate

Consolidated income taxes on earnings vary from the amount that would be computed by applying the Canadian and United States federal, British Columbia and Alberta combined statutory income tax rate of 40.82% (2000 – 44.21%) to earnings before income taxes and non-controlling interest as shown in the following table:

	2001	2000
Earnings before income taxes and non-controlling interest	$ 146.9	$ 125.6
Combined statutory income taxes	$ 60.0	$ 55.5
Add (deduct) tax effect of:		
Capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	(9.2)	(8.2)
Large Corporations Tax	6.1	4.8
Reduction in corporate tax rates and capital gains inclusion rate in future years	–	(8.5)
Non-taxable income and non-deductible expenses	(0.5)	(3.7)
Other	(0.5)	(2.0)
Actual consolidated income taxes on earnings	$ 55.9	$ 37.9

Future Income Taxes

The net future income tax liability of the Company of $56.8 million (2000 – $47.3 million) relates primarily to the tax effect of temporary differences on non-regulated property, plant and equipment balances.

As a result of the Company accounting for income taxes following the taxes payable method for its regulated operations, the Company has not recognized net future income tax liabilities amounting to $224.5 million at December 31, 2001 (2000 – $222.8 million) and has not recognized a future income tax recovery of $7.9 million for the year ended December 31, 2001 (2000 – $56.3 million), all of which were calculated under the asset and liability method.

10. ITEMS IN COMPARATIVE FIGURES

NW Energy Monetization

In 1999 the Company sold its interest in the cash flow of NW Energy (Williams Lake) Limited Partnership ("NW Energy"). The Company received net proceeds of $25.6 million which, along with income tax benefits that were recognized in 1999 and 2000, resulted in a gain of $7.0 million in 1999 and $29.0 million in 2000. The Company no longer owns any interest in NW Energy.

Restructuring Costs

The Company recorded a charge of $13.5 million ($7.5 million after income tax) in 2000 for costs relating to restructuring and relocation programs of petroleum transportation operations.

Non-Controlling Interest

The Utility redeemed 3,000,000 6.32% cumulative redeemable first preference shares of the Utility with a face value of $75.0 million on October 31, 2000 at $25 per share. Dividends paid on these shares in 2000 totaled $4.0 million.

11. EARNINGS PER SHARE

Basic earnings per share are based on the weighted average number of common shares outstanding during the year. Diluted earnings per share are based on the weighted average number of common shares and stock options outstanding at the beginning of or granted during the year. The Company's performance based share options are considered to be contingently issuable shares and have been included in the treasury stock method calculation only if all performance criteria of the options have been satisfied. The possible exchange of the $125.0 million Capital Securities into common shares has not been included in the treasury stock method calculation since similar obligations in the past have been paid wholly in cash.

The weighted-average number of outstanding shares at December 31, 2001 was 38.3 million (2000 – 38.3 million). The weighted-average number of net shares that would be issued under the treasury-stock method is 0.3 million (2000 – 0.3 million), producing diluted earnings per share of $2.19 (2000 – $2.82) on earnings applicable to common shares of $84.6 million (2000 – $108.8 million).

12. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The carrying values of cash, accounts receivable, short-term notes and accounts payable and accrued liabilities approximate their fair values due to the relatively short period to maturity of the instruments.

The fair value of the Company's long-term debt, calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2001, or by using available quoted market prices, is estimated at $2,314.4 million (2000 – $1,790.0 million). The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

Derivative Instruments

The Company uses derivative instruments to hedge its exposures to fluctuations in energy prices, interest rates and foreign currency exchange rates.

Natural gas derivatives are used to manage natural gas price risk in the natural gas distribution operations. The majority of the natural gas supply contracts have floating prices for natural gas, rather than fixed prices. On behalf of customers, the Company uses natural gas price swap contracts to fix the effective purchase price. Any differences between the effective cost of natural gas purchased and the price of natural gas used for rate making purposes are managed through the regulatory process whereby differences are recorded in a deferral account and passed through to customers in future rates.

The Company's short-term borrowings are exposed to interest rate risk. The Company manages interest rate risk through the use of interest rate derivatives.

Foreign currency risk in natural gas distribution operations relates mainly to purchases and sales of natural gas denominated in U.S. dollars, and is thereby managed mainly through the regulatory process. The only material foreign currency risk in the petroleum transportation and other activities segments relates to the U.S. portion of Trans Mountain's crude oil pipeline system. The Company manages foreign currency exposures through the use of foreign currency derivatives.

The carrying value of natural gas derivatives at December 31, 2001 was a liability of $27.9 million (2000 – asset of $20.4 million) and the fair value of the derivatives was a liability of $167.2 million (2000 – asset of $113.2 million). These derivatives have terms to maturity of up to two years as at December 31, 2001. The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates.

As at December 31, 2001, the Company had one interest rate derivative outstanding with a term of approximately seven years. The carrying and fair value of this derivative was not significant. There were no significant interest rate derivatives outstanding at the end of 2000, nor were there any significant foreign currency derivatives outstanding at the end of 2001 or 2000.

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. Because it deals with high credit quality institutions in accordance with its established credit approval practices, the Company does not expect any counterparties to fail to meet their obligations.

13. SEGMENT DISCLOSURES

The Company operates principally in two business segments:

(a) Natural gas distribution, primarily involving the transmission and distribution of natural gas for residential, commercial and large industrial customers in British Columbia; and

(b) Petroleum transportation, primarily involving the transportation of crude and refined petroleum products principally for seven major shippers from Alberta to the west coast of British Columbia and Washington State and the construction of the Corridor Pipeline.

The Company has other activities which include non-regulated energy and utility businesses as well as corporate interest and administration charges. The non-regulated businesses include water services and international consulting. The Company also operates in the United States. At the present time, these operations are not of sufficient size to be reportable as operating or geographic segments.

2001

	Natural gas distribution	Petroleum transportation	Other activities	Total
Revenues	**$ 1,420.3**	**$ 143.1**	**$ 102.9**	**$ 1,666.3**
Depreciation and amortization	**75.7**	**16.4**	**3.0**	**95.1**
Operating income (loss)	**234.6**	**61.6**	**(1.0)**	**295.2**
Financing costs	**126.1**	**13.5**	**8.7**	**148.3**
Income taxes (recovery) on earnings	**40.7**	**20.8**	**(5.6)**	**55.9**
Net earnings (loss)	**67.8**	**27.3**	**(4.1)**	**91.0**
Earnings (loss) applicable to common shares	**67.8**	**27.3**	**(10.5)**	**84.6**
Earnings (loss) per common share	**1.77**	**0.71**	**(0.27)**	**2.21**
Total assets	**2,757.9**	**834.7**	**113.1**	**3,705.7**
Capital expenditures	**146.0**	**307.6**	**16.2**	**469.8**

2000

	Natural gas distribution	Petroleum transportation	Other activities	Total
Revenues	$ 1,085.4	$ 132.5	$ 87.7	$ 1,305.6
Depreciation and amortization	67.1	17.7	1.4	86.2
Operating income	201.8	49.7	5.1	256.6
Financing costs	96.7	15.0	5.8	117.5
Restructuring costs	–	13.5	–	13.5
Income taxes (recovery) on earnings	42.4	(1.1)	(3.4)	37.9
Income tax benefits from NW Energy	–	–	(29.0)	(29.0)
Net earnings	58.7	22.3	31.7	112.7
Earnings applicable to common shares	58.7	22.3	27.8	108.8
Earnings per common share	1.53	0.58	0.73	2.84
Total assets	2,911.9	536.4	64.8	3,513.1
Capital expenditures	472.5	140.6	7.5	620.6

14. COMMITMENTS

(a) The Utility and Trans Mountain have entered into operating leases for certain building space and natural gas pipeline assets. Minimum payments under these leases are on average approximately $15.0 million in each of the next five years and $180.8 million in aggregate.

Included in these amounts are payments for an operating lease for certain natural gas pipeline assets which were sold in October 2001. The pre-tax gain of $23.4 million on cash proceeds of $47.5 million has been deferred and is being amortized over the 17-year term of the lease.

(b) The Company is constructing the Corridor pipeline at an estimated cost of $688 million, of which $429.8 million has been incurred to December 31, 2001.

CONSOLIDATED FINANCIAL INFORMATION (FIVE YEARS)

Unaudited

(Dollar amounts in millions) Years ended December 31	**2001**	2000	1999	1998	1997
STATEMENTS OF EARNINGS					
Operating revenue	**$ 1,666.3**	$ 1,305.6	$ 1,040.6	$ 925.0	$ 933.9
Operating expenses	**1,371.1**	1,049.0	784.7	664.5	689.9
Operating income	**295.2**	256.6	255.9	260.5	244.0
Other expenses	**148.3**	131.0	121.6	121.8	137.8
Income taxes	**55.9**	8.9	48.4	62.9	49.6
Non-controlling interest	**–**	4.0	4.7	4.6	5.8
Net earnings	**91.0**	112.7	81.2	71.2	50.8
Capital securities distributions	**6.4**	3.9	–	–	–
Earnings applicable to common shares	**$ 84.6**	$ 108.8	$ 81.2	$ 71.2	$ 50.8
ASSETS					
Current assets	**$ 503.5**	$ 631.2	$ 270.7	$ 224.9	$ 188.9
Property, plant and equipment (net)	**3,079.9**	2,727.6	2,185.1	2,168.6	2,116.1
Other assets	**122.3**	154.3	25.1	72.6	83.1
Total assets	**$ 3,705.7**	$ 3,513.1	$ 2,480.9	$ 2,466.1	$ 2,388.1
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities	**$ 857.7**	$ 1,094.4	$ 712.4	$ 858.1	$ 696.7
Long-term debt	**1,928.0**	1,561.9	1,001.8	906.7	993.3
Deferred gain	**23.1**	–	–	–	–
Other liabilities	**56.8**	47.3	140.4	111.3	109.9
Shareholders' equity	**840.1**	809.5	626.3	590.0	588.2
Total liabilities and shareholders' equity	**$ 3,705.7**	$ 3,513.1	$ 2,480.9	$ 2,466.1	$ 2,388.1
CASH FLOW DATA					
Operating cash flow	**$ 59.8**	$ 179.3	$ 124.1	$ 80.2	$ 170.6
Capital expenditures	**$ 469.8**	$ 620.6	$ 163.6	$ 128.7	$ 130.0

OPERATING INFORMATION (FIVE YEARS)

Unaudited

(Dollar amounts in millions) Years ended December 31	**2001**	2000	1999	1998	1997
NATURAL GAS DISTRIBUTION OPERATIONS					
Revenues					
Residential	**$ 813.6**	$ 627.8	$ 493.2	$ 423.1	$ 431.1
Commercial	**442.2**	336.3	262.2	226.3	246.9
Small industrial	**73.6**	52.3	26.7	22.5	17.3
Large industrial and other	**6.8**	7.7	8.8	19.1	19.7
Total natural gas sales revenue	**$ 1,336.2**	$ 1,024.1	$ 790.9	$ 691.0	$ 715.0
Transportation	**56.1**	41.0	38.4	33.6	28.6
Other	**28.0**	20.3	15.4	17.8	22.2
Total natural gas revenue	**$ 1,420.3**	$ 1,085.4	$ 844.7	$ 742.4	$ 765.8
Natural gas volumes (billion cubic feet)					
Sales volumes	**110.8**	124.0	121.8	117.1	123.0
Transportation volumes	**53.9**	56.3	57.6	52.1	52.0
Total natural gas volumes	**164.7**	180.3	179.4	169.2	175.0
Customers at year-end	**767,855**	762,878	755,383	742,305	732,316
PETROLEUM TRANSPORTATION OPERATIONS					
Revenues	**$ 143.1**	$ 132.5	$ 129.4	$ 135.4	$ 129.1
Transportation volumes (m^3/day)					
Canadian mainline	**33,270**	32,533	32,988	40,160	36,523
Jet fuel deliveries	**3,072**	3,149	3,196	3,260	3,279
Total throughput	**36,342**	35,682	36,184	43,420	39,802
U.S. mainline (included in Canadian mainline)	**11,671**	10,365	9,847	16,128	15,004
KILOMETRES OF PIPELINES					
Natural gas distribution operations	**37,430**	37,197	36,581	36,473	35,971
Petroleum transportation operations	**1,477**	1,477	1,477	1,477	1,477
Employees (consolidated)	**1,782**	1,966	1,869	1,819	1,979

CONSOLIDATED FINANCIAL INFORMATION (FIVE YEARS)

Unaudited

Years ended December 31	**2001**	2000	1999	1998	1997
RATIOS					
Return on average common equity	**12.1%**	12.0%	12.2%	12.1%	10.7%
Dividend payout ratio	**0.59**	0.43	0.55	0.59	0.77
Interest coverage ratio	**2.0**	2.2	2.1	2.1	2.1
Debt/debt plus shareholders' equity	**0.75**	0.71	0.71	0.73	0.71
Common shares outstanding – weighted average	**38.3**	38.3	38.3	38.5	40.1
DATA PER COMMON SHARE					
Earnings before non-recurring items	**$ 2.21**	$ 2.06	$ 1.94	$ 1.85	$ 1.63
Earnings applicable to common shares	**$ 2.21**	$ 2.84	$ 2.12	$ 1.85	$ 1.27
Dividends	**$ 1.300**	$ 1.225	$ 1.165	$ 1.090	$ 0.975
Operating cash flow	**$ 1.56**	$ 4.68	$ 3.24	$ 2.08	$ 4.25
Common equity	**$ 18.65**	$ 17.86	$ 16.36	$ 15.42	$ 15.05
Market price range – High	**$ 36.88**	$ 33.50	$ 31.40	$ 34.00	$ 28.00
– Low	**$ 29.00**	$ 21.50	$ 20.45	$ 25.50	$ 20.10
– Close	**$ 33.19**	$ 33.35	$ 25.40	$ 30.50	$ 27.80

QUARTERLY FINANCIAL INFORMATION

Unaudited

(In millions, except where stated otherwise)

2001	Three months ended March	June	September	December	Year ended December
Revenues	**$ 598.2**	**$ 345.5**	**$ 256.9**	**$ 465.7**	**$1,666.3**
Net earnings (loss)	**$ 62.5**	**$ (1.5)**	**$ (20.7)**	**$ 50.7**	**$ 91.0**
Earnings (loss) applicable to common shares	**$ 61.0**	**$ (3.1)**	**$ (22.3)**	**$ 49.0**	**$ 84.6**
Data per common share					
Basic earnings (loss)	**$ 1.59**	**$ (0.08)**	**$ (0.58)**	**$ 1.28**	**$ 2.21**
Diluted earnings (loss)	**$ 1.58**	**$ (0.08)**	**$ (0.58)**	**$ 1.27**	**$ 2.19**
Dividends paid	**$ 0.310**	**$ 0.330**	**$ 0.330**	**$ 0.330**	**$ 1.300**
Common share trading – TSE					
High	**$ 34.75**	**$ 35.10**	**$ 36.50**	**$ 36.88**	**$ 36.88**
Low	**$ 29.00**	**$ 30.12**	**$ 31.35**	**$ 32.07**	**$ 29.00**
Close	**$ 32.50**	**$ 31.85**	**$ 36.09**	**$ 33.19**	**$ 33.19**
Volume	**2.7**	**3.2**	**2.2**	**2.7**	**10.8**
Common shares outstanding – weighted average	**38.3**	**38.3**	**38.3**	**38.3**	**38.3**

2000					
Revenues	$ 383.9	$ 240.2	$ 213.9	$ 467.6	$ 1,305.6
Net earnings (loss)	$ 61.3	$ 9.6	$ (11.3)	$ 53.1	$ 112.7
Earnings (loss) applicable to common shares	$ 61.3	$ 8.5	$ (12.7)	$ 51.7	$ 108.8
Data per common share					
Basic earnings (loss)	$ 1.60	$ 0.22	$ (0.33)	$ 1.35	$ 2.84
Diluted earnings (loss)	$ 1.59	$ 0.22	$ (0.33)	$ 1.34	$ 2.82
Dividends paid	$ 0.295	$ 0.310	$ 0.310	$ 0.310	$ 1.225
Common share trading – TSE					
High	$ 26.50	$ 30.00	$ 30.20	$ 33.50	$ 33.50
Low	$ 21.50	$ 24.55	$ 26.40	$ 27.25	$ 21.50
Close	$ 25.00	$ 28.30	$ 28.35	$ 33.35	$ 33.35
Volume	4.7	2.3	1.9	2.2	11.1
Common shares outstanding – weighted average	38.3	38.3	38.3	38.3	38.3

BOARD OF DIRECTORS

Ronald L. Cliff, C.M., FCA
Chairman of the Board
West Vancouver, British Columbia
Chairman, BC Gas Inc.

Iain J. Harris
Vice Chairman of the Board
Vancouver, British Columbia
Chairman and Chief Executive Officer, Summit Holdings Ltd.

Robert G. Brodie
Barbados
Chairman, Cardiff Properties Limited

Brian A. Canfield
Point Roberts, Washington, U.S.A.
Chairman, TELUS

Donald A. Carlson
Edmonton, Alberta
President, Carlson Development Corporation Ltd.

Marilyn E. Cassady
Vancouver, British Columbia
Corporate Director

Pierre Choquette
Vancouver, British Columbia
President & Chief Executive Officer, Methanex Corp.

Mark L. Cullen
Vancouver, British Columbia
President, Mark Cullen & Company Ltd.

David L. Emerson
Vancouver, British Columbia
President and Chief Executive Officer, Canfor Corporation

John M. Reid
Vancouver, British Columbia
President and Chief Executive Officer, BC Gas Inc.

James M. Stanford
Calgary, Alberta
President, Stanford Resource Management Inc.

Robert T. Stewart
West Vancouver, British Columbia
President, R. T. Stewart & Associates

David W. Strangway
Vancouver, British Columbia
President, Canada Foundation for Innovation

Douglas W. G. Whitehead
Coquitlam, British Columbia
President and Chief Executive Officer, Finning International Inc.

BC Gas Inc. directors are also directors of BC Gas Utility Ltd. and Trans Mountain Pipe Line Company Ltd.

COMMITTEES OF THE BOARD

Audit Committee

I. J. Harris (Chair),
B. A. Canfield, M. L. Cullen, D. L. Emerson and R. T. Stewart

Acts on behalf of the Board in reviewing certain financial information prepared for public distribution and in monitoring internal accounting controls. The Committee is responsible for assuring that the Company's financial statements accurately portray the financial condition of the Company and for providing reasonable assurances that the Company is in compliance with applicable laws and regulations, is conducting its affairs ethically and maintains effective controls. The Committee also recommends the appointment, change or reappointment of auditors.

Management Resources Committee

D. W. G. Whitehead (Chair),
P. Choquette, I. J. Harris, R. T. Stewart and D. W. Strangway

Ensures the Company has a plan for continuity of its officers and an executive compensation plan that is motivational and competitive in order to attract, hold and inspire the performance of Executive Management and other key personnel. The intent of the Committee is to enhance the profitability and growth of the Company through effective succession planning.

Corporate Governance Committee

D. W. Strangway (Chair),
R. G. Brodie, B. A. Canfield, D. A. Carlson and M. L. Cullen

Ensures that an effective and efficient approach to corporate governance is developed and implemented, with the objective of assuring the business and affairs of the Company are carried out in a manner that will enhance shareholder value. In consultation with the Chairman of the Board, the Committee is responsible for identifying, evaluating and recommending nominees for the Board of Directors.

Environment and Safety Committee

M. E. Cassady (Chair),
R. G. Brodie, I. J. Harris and D. W. G. Whitehead

Reviews and approves corporate environmental policy, evaluates the Company's progress in implementing the policy, reviews relevant data and reports, brings information and recommendations to the attention of the Board as appropriate.

OFFICERS

BC GAS INC.

Ronald L. Cliff, C.M., FCA
Chairman of the Board

Iain J. Harris
Vice Chairman

John M. Reid
President and Chief Executive Officer

Gordon R. Barefoot
Senior Vice President, Multi-Utility Services

Mary E. Bruce
Senior Vice President, Human Resources

Milton C. Woensdregt
Senior Vice President, Finance and Chief Financial Officer, and Treasurer

Patrick D. Lloyd
Senior Vice President, Legal & Government Affairs

Stephen M.G. Richards
General Counsel, Chief Risk Officer and Corporate Secretary

Debra G. Nelson
Assistant Corporate Secretary

BC GAS UTILITY LTD.

Ronald L. Cliff, C.M., FCA
Chairman of the Board

Iain J. Harris
Vice Chairman

John M. Reid
Chief Executive Officer

Randall L. Jespersen
President

Mary E. Bruce
Senior Vice President, Human Resources

Milton C. Woensdregt
Senior Vice President, Finance and Chief Financial Officer, and Treasurer

Ronald J. Jupp
Vice President, Distribution Operations

Jan A. Marston
Vice President, Marketing

David M. Masuhara
Vice President, Regulatory, Environment & Safety, Supply Chain & Logistics

Robert M. Samels
Chief Information Officer & Vice President Information Technology

Douglas L. Stout
Vice President, Gas Supply, Transportation & Transmission

David A. Zerr
Vice President, Network Development & Operations Support

Stephen M. G. Richards
General Counsel, Chief Risk Officer and Corporate Secretary

Debra G. Nelson
Assistant Corporate Secretary

TRANS MOUNTAIN PIPE LINE COMPANY LTD.

Ronald L. Cliff, C.M., FCA
Chairman

John M. Reid
Vice Chairman

Thomas D. Doyle
President

Richard T. Ballantyne
Executive Vice President

John L. Fingarson
Vice President, Secretary and General Counsel

Michael R. Horner
Vice President, Corridor Pipeline Project

Robert D. Vergette
Vice President, Operations

Liisa A. O'Hara
Vice President, Financial Services & Regulatory Affairs

Milton C. Woensdregt
Treasurer

Michael W. P. Boyle
Corporate Solicitor and Assistant Secretary

Cheryl L. Berge
Controller and Assistant Treasurer

INVESTOR INFORMATION

ANNUAL GENERAL MEETING

The Annual General Meeting of Shareholders will be held at 11:00 a.m. on Thursday, April 25, 2002 at the Waterfront Hotel in Vancouver, British Columbia.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Registered holders of the Company's common shares (except residents of the United States) may elect to reinvest their cash dividends in new common shares. Participants in the Plan may also make optional cash payments of up to $20,000 per calendar year to purchase additional common shares. Optional cash payments must be received by the Registrar and Transfer Agent by the last days of January, April, July and October to be reinvested on the following dividend payment date. There are no brokerage commissions payable on shares purchased pursuant to the Plan. For an information package on the Plan, or to register in the Plan, please contact Shareholder Relations.

EMPLOYEE SHARE PURCHASE PLAN

Employees of BC Gas Utility Ltd. may contribute from 2% to 6% of their earnings through payroll deductions to purchase the Company's common shares. Shares are purchased at 100% of the market price.

COMMON SHARE DISTRIBUTION

Approximately 99.2% of the outstanding common shares are owned by residents of Canada. The following table summarizes the distribution of shares at December 31, 2001.

	Shareholders	Shares
Canada	6,615	42,594,127
USA	96	291,406
Others	29	50,526
Total	6,740	42,936,059

COMMON SHARE OWNERSHIP CONSTRAINTS

In accordance with the statute that privatized the Company, the following constraints on BC Gas Inc. share ownership exist: (i) the total number of voting shares held by any one person or associated persons shall not exceed 10% of the total number of issued and outstanding voting shares; and (ii) non-Canadian citizens and non-residents of Canada will not be permitted to hold or beneficially own in the aggregate, directly or indirectly, more than 20% of the total number of the issued and outstanding voting shares of the Company.

Valuation Day Value
(Dec. 22, 1971)
Common Shares[1] $6.50
Feb. 22, 1994 Closing Price, $15.50

[1]Adjusted for the two-for-one stock split on November 18, 1985.

REGISTRAR AND TRANSFER AGENT

Shareholder accounts, including dividend payments, direct deposit service and the transfer of shares are handled by the Company's registrar and transfer agent:

CIBC Mellon Trust Company,
16th Floor
1066 West Hastings Street
Vancouver, B.C. V6E 3X1
Telephone: 604-688-4330
Toll Free: 1-800-387-0825
Fax: 604-688-4301
Web site: www.cibcmellon.com

DUPLICATE ANNUAL AND INTERIM REPORTS

To eliminate duplicate mailings of annual and quarterly reports, please contact CIBC Mellon Trust Company.

SHARES LISTED (Symbol: BCG)

The Toronto Stock Exchange

SCHEDULED DIVIDEND PAYMENT DATES

February 28, 2002
May 31, 2002
August 31, 2002
November 30, 2002

Project management: Arlette Communication Inc.   This report is printed on recycled paper.

SHAREHOLDER RELATIONS

Inquiries regarding the Company's Dividend Reinvestment and Share Purchase Plan and all other inquiries or comments by shareholders regarding the Company should be directed to:

Debra Nelson
Telephone: 604-443-6559
Toll Free (Canada): 1-800-667-9177
Fax: 604-443-6789
E-mail: shareholder@bcgas.com

INVESTOR RELATIONS

Portfolio managers, investment analysts and other investors requesting financial information regarding BC Gas should contact:

David Bryson
Telephone: 604-443-6527
Fax: 604-443-6929
E-mail: ir@bcgas.com

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BC Gas Utility Ltd.
16705 Fraser Highway
Surrey, B.C. V3S 2X7
Main Telephone: 604-576-7000
Toll Free: 1-800-773-7001

Trans Mountain Pipe Line Company Ltd.
#2700, 300 - 5th Avenue SW
Calgary, Alberta T2P 5J2
Telephone: 403-514-6400

INTERNET

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